PCT

WORLD INTELLECTUAL PROPERTY ORGANIZATION
International Bureau

INTERNATIONAL APPLICATION PUBLISHED UNDER THE PATENT COOPERATION TREATY (PCT)

(51) International Patent Classification 5 : G01V 1/40 | A1

(11) International Publication Number: WO 93/07514

(43) International Publication Date: 15 April 1993 (15.04.93)

(21) International Application Number: PCT/US92/08412

(22) International Filing Date: 2 October 1992 (02.10.92)

(30) Priority data:
771,758 4 October 1991 (04.10.91) US

(71) Applicant: ATLANTIC RICHFIELD COMPANY [US/US]; 2300 West Plano Parkway, Plano, TX 75075 (US).

(72) Inventors: AIRHART, Tom, Patterson ; 2425 Maple Leaf Drive, Plano, TX 75075 (US). MONTGOMERY, Melvin, G. ; 1504 Amherst, Plano, TX 75075 (US). KINGMAN, John, E., E. ; 1865 Post Oak Park, Houston, TX 77027 (US). LIVESAY, Ronald, B. ; 2417 Fifth Avenue, Fort Worth, TX 76110 (US).

(74) Agent: MARTIN, Michael, E.; Atlantic Richfield Company, 2300 West Plano Parkway, Plano, TX 75075 (US).

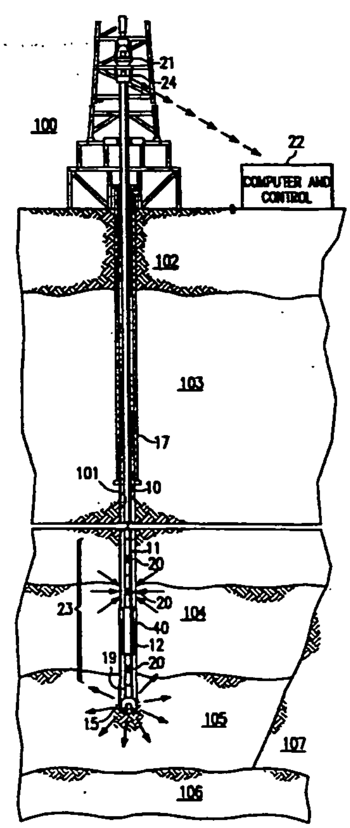
(81) Designated States: AU, CA, NO, European patent (AT, BE, CH, DE, DK, ES, FR, GB, GR, IE, IT, LU, MC, NL, SE).

Published
With international search report.

(54) Title: SYSTEM FOR REAL-TIME LOOK-AHEAD EXPLORATION OF HYDROCARBON WELLS

(57) Abstract

A system and method for performing seismic prospecting and monitoring during drilling of a well (101) are disclosed. The system generates energy, such as acoustic vibrations and electromagnetic energy, at a downhole location (15) and imparts the same into the surrounding earth. The energy may be imparted by the drilling operation itself, or may be generated by a downhole apparatus. Downhole sensors (20) are provided which sense the energy after it has passed through the earth (104) surrounding the wellbore. The sensed energy is either communicated to the surface, or is communicated to a downhole computer for analysis, with the results of the analysis communicated to the surface. Due to the use of both downhole generation and sensing of the energy, high frequency energy may be used. As a result, the resolution of the resulting survey is improved over techniques which utilize surface detectors for energy traveling through the earth.



FOR THE PURPOSES OF INFORMATION ONLY

Codes used to identify States party to the PCT on the front pages of pamphlets publishing international applications under the PCT.

AT	Austria	FR	France	MR	Mauritania
AU	Australia	GA	Gabon	MW	Malawi
BB	Barbados	GB	United Kingdom	NL	Netherlands
BE	Belgium	GN	Guinea	NO	Norway
BF	Burkina Faso	GR	Greece	NZ	New Zealand
BG	Bulgaria	HU	Hungary	PL	Poland
BJ	Benin	IE	Ireland	PT	Portugal
BR	Brazil	IT	Italy	RO	Romania
CA	Canada	JP	Japan	RU	Russian Federation
CF	Central African Republic	KP	Democratic People's Republic of Korea	SD	Sudan
CG	Congo			SE	Sweden
CH	Switzerland	KR	Republic of Korea	SK	Slovak Republic
CI	Côte d'Ivoire	LI	Liechtenstein	SN	Senegal
CM	Cameroon	LK	Sri Lanka	SU	Soviet Union
CS	Czechoslovakia	LU	Luxembourg	TD	Chad
CZ	Czech Republic	MC	Monaco	TG	Togo
DE	Germany	MG	Madagascar	UA	Ukraine
DK	Denmark	ML	Mali	US	United States of America
ES	Spain	MN	Mongolia	VN	Viet Nam
FI	Finland				

SYSTEM FOR REAL-TIME LOOK-AHEAD EXPLORATION OF HYDROCARBON WELLS

This invention is in the field of hydrocarbon exploration, and is more specifically directed to real-time data acquisition and processing during the drilling operation.

Background of the Invention

While the drilling of wells for the production of hydrocarbons, such as oil and natural gas, has always been quite expensive, even more attention has been paid to drilling costs in recent years. This is due in part to the increasing depth and difficulty of location of remaining hydrocarbon reserves, considering that many shallow and large reservoirs have already been heavily exploited. As drilling costs increase at least linearly with the depth of the well being drilled, newer wells are becoming increasingly expensive. Drilling in hostile surface or sub-surface environments increases the drilling costs. Furthermore, the volatility of prices in the oil and gas markets in recent years has reduced operating profit margins, and thus has placed significant pressure on producers to drill only where the likelihood of paying production is high.

Faster and more efficient drilling, in distance drilled per unit time, is of course highly desired to contain these costs. However, overpressurized sub-surface zones present significant problems to drilling in many locations, as drilling into such a zone causes a blow-out

if the pressure of the hydrocarbon (generally natural gas) in the zone exceeds the pressure in the wellbore to such an extent that the hydrocarbon explodes out of the well. In locations where overpressurized zones are expected, drilling must be performed using heavy drilling mud to increase the pressure in the wellbore to hold the hydrocarbon in the overpressurized zone in place when the zone is reached. As is well known in the art, however, drilling with such heavier muds is significantly slower than drilling with lighter muds. Due to the limited accuracy with which conventional seismic surveys can predict the depth of such zones, heavy mud is used over relatively long distances to provide sufficient safety margin. As a result, drilling efficiency is significantly impacted by such conventional drilling and exploration techniques.

In addition, while the use of heavy muds reduces the likelihood of a blow-out, excessively heavy mud used during drilling can damage surrounding formations if the mud pressure is significantly greater than the so-called pore pressure in the earth. Therefore, the weight of the drilling mud has both an upper and a lower limit, outside of which drilling failure can occur.

Inaccuracies in the conventional surface geophysical surveys of course also add uncertainty to the success of the well in reaching any hydrocarbon reservoir. Particularly in many regions of the earth where exploration is currently taking place, reservoirs are limited in size, or may have a narrow cross-section in the plan view. A well drilled according to a conventional survey may narrowly miss the reservoir, where small deviations in the drilling direction would have resulted in success for the well.

For these and other reasons, it is therefore beneficial to acquire accurate information about the physical properties of the formations being drilled during the drilling operation, particularly concerning formations which are ahead of the drill bit. Such information can supplement that which was previously acquired by conventional surface geophysical surveys, and allow for control of the drilling to adjust for any differences between previously acquired information and the actual formations encountered. Furthermore, it is also beneficial to acquire accurate real-time information concerning certain drilling parameters, such as weight-on-bit, RPM, direction of the drill bit, and the like. This information, particularly in combination with surface survey information and information acquired during the drilling about the formations through which drilling has taken place and also into which drilling is about to take place, can allow for intelligent drilling, with parameters modified and adjusted on a real-time basis for maximum efficiency and the highest chances for successful production therefrom. The ability to acquire and utilize this type of real-time data is the goal of the invention described hereinbelow.

By way of background relative to the current state of the art, one type of exploration while drilling method which is known in the art is the "TOMEX" method presently offered by Western Atlas International, Inc. According to this method, energy imparted into the earth by the drill bit, during the drilling operation, is considered as the source energy for seismic surveying, with reflections of this source energy detected by geophones deployed at surface locations away from the drilling location. The "TOMEX" survey method is described in numerous publications, including Rector III, et al., "Extending VSP to 3-D and MWD: Using the drill bit as downhole seismic

source", Oil and Gas Journal, (June 19, 1989), pp. 55-58, and in Rector, Marion and Widrow, "Use of Drill-Bit Energy as a Downhole Seismic Source", 58th International Meeting of SEG, paper DEV 2.7, pp. 161-164, U.S. Patents 4,363,112 and 4,365,322, and PCT publication WO 88/04435.

However, certain limitations are believed to be present relative to the use of downhole seismic sources in conjunction with surface receivers, such as in the "TOMEX" survey method. Firstly, due to the distance traveled by the seismic energy through the earth, only relatively low frequency (and long wavelength) energy is useful. As a result, the resolution of such surveys is necessarily limited. Secondly, it is quite difficult to obtain an accurate source signature, or pilot signal, from vibrations transmitted along the drill string from the bit to the surface. For example, in the "TOMEX" survey where the source signal is detected by monitoring drill string vibrations, noise of significant amplitude couples into the source vibrations detected at the surface, making determination of the source signature (for purposes of later correlation with the geophone-detected vibrations) difficult and inaccurate. Such difficulties with the noise in drill string vibrations are described in U.S. Patent No. 5,130,951, issued July 14, 1992, assigned to Atlantic Richfield Company and incorporated herein by reference, in J.P DiSiena et al., "VSP While Drilling: Evaluation of TOMEX", Exploration Technology Report (Atlantic Richfield Company, Fall 1989), pp. 13-20, and also in U.S. Patent No. 4,954,998.

By way of further background, other known analysis methods utilize energy that is generated downh le (for example by the drill bit) and detected at the surface, besides that described hereinabove for seismic surveying. For example, the vibrations in the drill string which are

generated by the interaction of the drill bit with the formation can be detected at the surface and analyzed to provide real-time monitoring of drilling conditions and parameters. U.S. Patent No. 4,715,451, issued December 29, 1987, assigned to Atlantic Richfield Company and incorporated herein by reference, describes a method and system for monitoring drilling parameters by way of spaced apart subs at the upper end of the drill string, such subs including accelerometers and strain gauges. The monitored parameters include axial and torsional loading on the drill bit, axial and torsional drillstring vibrations, and bending modes of the drillstring.

By way of further background, other "measurement-while-drilling", or "MWD", techniques utilize downhole sensors of various parameters, in combination with one of several approaches for telemetry of the detected parameters. Various examples of such approaches are described in Honeybourne, "Measurement While Drilling", Symposium on the 75th Anniversary of the Oil Technology Course at the Royal School of Mines (1988), particularly relative to mud pulse telemetry.

U.S. Patent 4,992,997, issued February 12, 1991, assigned to Atlantic Richfield Company and incorporated herein by reference, describes a stress wave telemetry system for monitoring downhole conditions during drillstem testing, or during wellbore stimulation or fracturing; this system includes accelerometers or strain gauges mounted onto the drillstem near the surface, for sensing torsional, axial or bending vibrations in the drillstem which may be correlated to downhole conditions. PCT Publications WO 92/01955 and 92/02054, both assigned to Atlantic Richfield Company, and both incorporated herein by this reference, describe another example of a telemetry system, where a transducer disposed within the drill string provides high

data rate telemetry from downhole to the surface by way of acoustic axial or torsional vibrations. These techniques communicate data on a real-time basis, without requiring that drilling be stopped as in the case of conventional well log tools and techniques.

By way of additional background, conventional wireline logging tools are used to evaluate the properties of formations surrounding wellbores, in conjunction with drilling operations. These logging tools are lowered into the wellbore periodically in the operation, with the actual drilling and excavation stopping during the logging operation. These downhole logging tools include radioactive and electromagnetic instrumentation, of various types.

A first type of electromagnetic logging tool is the direct coupled, or galvanic, logging tool. An example of a currently available galvanic logging tool are those of the well-known "Laterolog" type, available from Schlumberger. Such galvanic logging tools source a current into the earth from one electrode, for example the upper portion of the drill string, and measure a potential difference with other electrodes in the logging tool. Conventional galvanic logging tools have a relatively shallow depth of investigation (on the order of inches to several feet), as the information of interest is the resistivity of the formation immediately outside of the so-called invaded zone; accordingly, the distance between a potential-measuring electrode and one of the current electrodes is quite small. Logging tools of the Laterolog type include an opposing current, to focus the investigation into the formation within a narrow plane perpendicular to the borehole. The Laterolog principles are also used in "measurement-while-drilling" galvanic

tools, such as available as the "FCR" measurement system from EXLOG.

The second type of electromagnetic wireline logging tool is often referred to as an electromagnetic induction tool. In this tool, two coils are lowered into the wellbore, separated along the axial length of the wellbore. One of the coils is energized to produce electromagnetic waves of known frequency and amplitude, and the other coil measures the electromagnetic energy it receives from the first coil, after the waves have traveled through the formation. Analysis of the amplitude attenuation and phase shift of the received waves from the transmitted waves will be indicative of the impedance of the surrounding formation.

In the case of these induction tools, it should be noted that the measurement is directed substantially perpendicular to the axis of the wellbore (at the location of the tool), but only for a limited distance. This is due to the purpose of this tool of determining the local resistivity of the surrounding formation, assuming homogeneity of the formation. The distance of interest from the wellbore is preferably far enough away so that the effects of drilling mud packing into the near-wellbore layer of the formation are minimized, but not far enough away that another formation type is encountered by the waves. Since the logging by this tool assumes (and relies upon) homogeneity of the measured layer, the readings and analysis of the received energy from multiple formation types is undesired. Typical distances over which the waves of interest travel are on the order of 10 feet from the wellbore, in substantially a perpendicular plane therefrom.

"Logging-while-drilling" tools, which provide surrounding formation analysis by monitoring certain types

of radioactivity (such radioactive measurements conventional for wireline logging tools) and which apparently may be used during drilling, are known to have been developed by Magnetic Pulse, Inc. The measurements available from this tool include the passive measurements of gamma ray emission from the surrounding formation, including spectral analysis of the gamma ray emission to determine the presence of certain elements in the formation. The tool is also apparently capable of neutron density measurements, as the tool has a neutron source (such as AmBe) and detector, such that the density of the formation can be determined by the number of neutrons detected after back-scattering by the formation to the neutron detector. A Cesium gamma ray source in such a tool is also known, such that density measurements may also be made by detecting gamma ray back-scatter from the formation.

By way of further background, Bradley, et al., "Microprocessor-Based Data-Acquisition System for a Borehole Radar", IEEE Trans. Geoscience & Remote Sensing, Vol. GE-25, No. 4 (IEEE, 1987) describes the use of a downhole radar tool for evaluating the formations surrounding the wellbore. By way of still further background, van Popta et al., "Use of Borehole Gravimetry for Reservoir Characterisation and Fluid Saturation Monitoring", Publication 988 (Shell Internationale Research Maaschappij B.V., 1990) describes a method of measuring secondary gas saturations in a fractured reservoir using borehole gravimetry.

By way of further background, U.S. Patents No. 4,929,896, 4,906,928, 4,843,319, 4,839,593 and 4,929,898, all assigned to Atlantic Richfield Company and all incorporated herein by reference, describe systems for the measurement of the thickness of a conductive container,

such as a pipe, by way of current induction. This method is commonly referred to as transient electromagnetic probing, or "TEMP". In these systems, a transmitting antenna generates a magnetic field, which in turn produces eddy currents in the conductive container being measured. These eddy currents produce a magnetic field, which is measured by a receiving antenna. The rate of decay of the measured current corresponds to the rate of decay of the eddy currents in the container being measured, which corresponds to the thickness of the conductive walls or coating of the container. Accordingly, these systems allow for non-contact measurement of the thickness of containers such as petroleum pipelines, so that the effects of corrosion may be monitored.

It is an object of this invention to provide a method and system for obtaining accurate seismic data, with high spatial resolution, which looks ahead of the drill bit during the drilling operation into nearby formations.

It is a further object of this invention to provide such a method and system which utilizes acoustic vibrations generated by the drill bit as the source for such data.

It is a further object of this invention to provide such a method and system which utilizes electromagnetic energy, both DC and induction, generated downhole.

It is a further object of this invention to provide such a method and system which can detect approaching overpressurized zones, so that drilling efficiency may be maximized by use of heavier drilling muds only in those regions at and near such overpressurized zones.

It is a further object of this invention to provide such a method and system which can pr vide for optimized

casing design, relative to the heavy weight mud which must be used once such an overpressurized zone is reached.

It is a further object of this invention to provide such a method and system which includes downhole sensors of downhole-generated source energy, to provide for improved accuracy in the resulting data analysis.

It is a further object of this invention to provide such a method and system which includes high data rate telemetry for communication of the downhole sensed energy, to provide improved resolution look-ahead analysis.

It is a further object of this invention to provide such a method and system which includes downhole computing capability sufficient to provide real-time analysis of the downhole-sensed information, such that the results of the analysis can be communicated to the surface with even relatively low data rate telemetry.

It is a further object of this invention to provide such a method and system which utilizes downhole computing capability of sufficient performance as to allow conventional low data rate downhole-to-surface telemetry to communicate the results.

It is a further object of this invention to provide such a method and system which includes spaced apart downhole sensors for purposes of reduction of noise, and so that the resulting analysis can determine the location of certain sub-surface structures.

It is a further object of this invention to provide such a method and system which can provide information regarding the temperature and pressure near the bottom of the wellbore at data rates high enough so that pressure

dynamics of flow and reservoir recovery can be used to assist in characterization of the reservoir.

It is a further object of this invention to provide such a method and system which can provide information regarding wellbore pressure, time rate of change of pressure, and pH of the surrounding fluid, in order to monitor the progress of acid treatment completion of oil and gas wells, and in order to monitor the extent of formation fracturing in completing oil and gas wells.

It is a further object of this invention to provide such a method and system which provides real-time drilling parameter monitoring capability in an improved manner.

It is a further object of this invention to provide such a method and system which can detect the presence of faults and interfaces which are at angles other than perpendicular to the direction of drilling.

It is a further object of this invention to provide such a method and system which can monitor parameters of formations through which drilling has already taken place, and to use this monitored information in providing a survey relative to formations into which drilling has not yet taken place.

It is a further object of this invention to provide such a method and system which utilizes spaced apart detection locations along the drill string so that drillstring interaction and distributed operator response characteristics can be measured.

Other objects and advantages of this invention will be apparent to those of ordinary skill having reference to the following specification together with the claims.

Summary of the Invention

The invention may be incorporated into a downhole system, for example a drilling rig, where energy is imparted into the surrounding formation near the bottom of the wellbore. The energy may be vibrational energy, including that generated by the drill bit itself, or may be electromagnetic energy generated by a downhole source of the same. Sensors are provided at one or several downhole locations along the drill string, for detecting the imparted energy after it has traveled through the surrounding formation. The sensors may include accelerometers, strain gauges, and fluid pressure detectors, where the energy is acoustic vibrations; for electromagnetic energy, the sensors may include coils or resistivity probes.

Due to the provision of the downhole sensors, the operating frequencies of the energy may be quite high, thus providing high resolution information regarding the composition of the surrounding formations. In addition, the sensors are deployed in such a manner that energy is received from a relatively large volume surrounding the wellbore, including formations which are ahead of the drill bit. In addition, selection of the downhole sensor and frequencies of the energy can be varied to, in turn, vary the depth of investigation. Accordingly, both high resolution logging in the conventional sense and lower resolution look-ahead and look-around logging may be accomplished by the same system.

The detected energy may be communicated to the surface by way of high speed telemetry, including hardwired telemetry or stress wave telemetry, which can transmit the information at relatively high data rates commensurate with

the high frequency information generated and detected. Alternatively, downhole computing equipment may be provided which is particularly adapted to performing complex analysis of the detected energy, with the results of the analysis communicated to the surface by way of either low or high data rate telemetry.

The invention provides for increased visibility into formations ahead of and surrounding the wellbore, on a real-time basis during the drilling operation. This increased visibility can be used in order to verify prior seismic surveys of the drilling location. For example, where drilling is being performed into an area where the stratigraphy is known, this visibility provides verification of the geologic location of the drilling operation; conversely, where drilling is being performed into an area where only a surface seismic survey has been performed, this visibility provides verification of the seismic location of the drilling. The invention can also provide accurate prediction of the properties of formations into which drilling is about to occur. Of particular importance is the ability of a system according to the invention to provide real-time information concerning overpressurized formations immediately ahead of the bit, so that heavy drilling mud need only be provided as such zones are approached rather than throughout the drilling as may now be necessary when drilling at locations for which less accurate surveys are provided. By limiting the length during which the heavier drilling mud is used, and by thus maximizing the length over which lighter drilling fluids are used, the efficiency and speed of the drilling operation is greatly increased.

In addition, the invention provides the ability to monitor the drilling operation itself by sensing and communicating drilling param ters, and also the ability to

characterize the formations as the drilling takes place therethrough. Information concerning the surrounding formations also can be used to direct the drilling operation into reservoirs which may be located near the wellbore, but which would not be intersected if the drilling continued along its current path. In addition, monitoring the drilling parameters such as RPM, WOB and the like, allows for their real-time control and optimization of the drilling operation to increase the rate of penetration, as well as reducing the likelihood of washouts, twist-offs and other drilling failures.

Brief Description of the Drawings

Figure 1 is a schematic illustration of a generalized system according to the present invention.

Figure 2a is a schematic diagram of a seismic measurement-while-drilling logging tool according to a first embodiment of the present invention.

Figure 2b is an elevation view of a portion of the tool of Figure 2a, illustrating potential paths for the seismic energy from bit to detector.

Figures 3a and 3b are cross-sectional diagrams of a detector in the tool of Figure 2a.

Figure 4 is a set of timing diagrams, illustrating an example of the energy received by the detector of Figures 3a and 3b from the bit, along the various paths illustrated in Figure 2b.

Figure 5 is an elevation view schematically illustrating the construction and operation of a galvanic logging tool according to a second embodiment of the invention.

Figure 6 is a plot illustrating an example of resistivity measurements obtained by the tool of Figure 5 during the span of a drilling operation.

Figures 7a and 7b are plots of resistivity versus depth and resistivity versus electrode position, respectively, for an example of the tool of Figure 5.

Figure 8 is a cross-sectional diagram illustrating an electromagnetic induction logging tool according to another embodiment of the invention.

Figure 9 is an electrical schematic for one coil in the embodiment of Figure 8.

Figure 10 is a cross-sectional diagram illustrating an example of the use of the tool of Figure 8.

Figure 11 is a plot of magnetic dipole moment versus time, as useful in the operation of the embodiment of Figures 8 and 10.

Figures 12a and 12b are contour plots of the eddy currents generated according to the embodiment of Figures 8 and 10.

Figure 13 is an electrical diagram, in block diagram form, of a data processing system useful according to the present invention.

Figure 14 is an electrical diagram, in block diagram form, of the data processing system of Figure 13 in stand-alone form.

Detailed Description of the Preferred Embodiments

The following description of the preferred embodiments of the invention will begin with description of the context and environment into which the present invention may be applied. The generation and detection of alternative energy types, and alternative telemetry and downhole computing systems, will be described in further detail thereafter.

I. Overview of the real-time look-ahead prospecting and monitoring system

Referring to Figure 1, the context of the present invention, and an overview of its objects and advantages, will now be described. Figure 1 illustrates drilling rig 100 in the process of drilling a wellbore into the earth for purposes of producing hydrocarbons from sub-surface reservoirs. Drilling rig 100 includes drill string 10 which is suspended from a conventional derrick, and which, in this example, is powered by swivel 21 at the surface, in the conventional top-drive rotary fashion. At the distal end of drill string 10 from the surface is a conventional drill bit 15. The rotation of drill string 10 from swivel 21, together with the weight of drill string 10 on bit 15, causes excavation of the earth by drill bit 15 to form wellbore 101 along the drilling path.

At the stage of the drilling operation shown in Figure 1, wellbore 101 has been drilled from the surface through sub-surface strata 102, 103, and 104, with drilling currently taking place into stratum 105 and approaching stratum 106. A porti n of the w llbore 101 is lined with casing 17, in the example shown in Figure 1. As is

conventional in the art, the annular portion of wellbore 101 surrounding drill string 10 will generally be filled with drilling fluid, or "mud". As is also conventional in the drilling art, such drilling mud is provided by pumping the same into drill string 10 from the surface, with the mud exiting from drill bit 15 at the downhole end of drill string 10 and returning to the surface via wellbore 101. The drilling mud not only lubricates the excavation action of the drill bit, but also serves to remove the cuttings from the excavation site, carrying the same to the surface. Also as is well known, drilling mud, if of sufficient weight and density, can prevent the explosive release of hydrocarbons out of wellbore 101, in the event that a highly pressurized hydrocarbon reservoir is reached by drill bit 15.

Particularly in locations where the cost of drilling is quite high, it is conventional to have a seismic survey performed of the region surrounding the drilling location prior to commencing drilling, such that the likelihood of reaching a hydrocarbon reservoir is predictable. Such surveys will, of course provide some indication of the presence and depth of the various sub-surface strata 102 through 106, and the interfaces therebetween. As is well known, hydrocarbon products, such as oil and gas, may reside in certain strata, or in interfacial traps between the same. However, while modern survey techniques can be relatively accurate in providing a survey of the drilling field, both recent surveys and particularly older surveys will be somewhat inaccurate in determining the depth of the sub-surface strata and interfaces. As a result, particularly if it is expected that highly pressurized regions will be drilled into, significant safety margin must be incorporated into the design of the drilling operation, to prevent explosive "blow-outs" at such time as those regions are reached.

In many drilling operations where such blow-outs are feared, extremely heavy drilling mud is conventionally used to reduce the risk and severity of reaching an over-pressurized zone. The heavy drilling mud increases the pressure within wellbore 101 near bit 15, increasing the pressure at which a blow-out can occur. However, the use of such heavy drilling mud decreases the drilling speed, thereby increasing drilling costs. Accordingly, inaccuracies (either actual or perceived) in the seismic survey require excessive use of heavy drilling muds add significant expense to the drilling operation, and also increases the risk of damaging formations that may otherwise have produced hydrocarbons.

Of course, inaccuracies in the seismic survey can also result in unsuccessful drilling. Referring to Figure 1, region 107 is illustrated at a location adjacent to wellbore 101, but in a location which will not be reached so long as the drilling continues along its same path. The shape of region 107 is particularly troublesome to detect in conventional seismic surveys, as it has a boundary which is substantially vertical. If region 107 were the reservoir from which production is sought via the drilling operation of Figure 1, the illustrated well would be unsuccessful.

The present invention is directed to providing real-time look-ahead information about the surrounding sub-surface formation so that prior seismic surveys can be verified, or to provide a new survey by sensing the presence and depth of layers not previously found. The present invention can also provide information about current drilling parameters, as will also be described in detail hereinb low.

By way of overview, according to the present invention, energy is emitted from a downhole source, such as drill bit 15 or a source near drill bit 15, as illustrated in Figure 1. According to the present invention, tool 23, having one or more downhole detectors 20 and data handling unit 40, is coupled between drill string 10 and bit sub 19; bit sub 19 is connected to drill bit 15. Within tool 20, at least one detector 20 is placed as close to drill bit 15 as possible, preferably within several feet of bit 15. If multiple detectors 20 are deployed in tool 20, these detectors 20 are preferably spaced from one another, as will be described in more detail hereinbelow. Detectors 20 sense the energy originally generated by drill bit 15 or such other source, after the energy has traveled through surrounding formations, including energy which has reflected from interfaces in advance of or otherwise near wellbore 10.

As a result of this configuration, both an energy source and energy detector are provided downhole. The distances required for the travel of the energy are much shorter (e.g., on the order of tens of feet) than that in prior seismic MWD methods, such as the above-noted "TOMEX" method, where the energy travels from the drill bit 15 to the surface through hundreds, or even thousands, of feet of earth. The shorter travel distances in the system according to the present invention allow for the use of higher frequency energy, including high frequency seismic vibrations (on the order of 100 to 2000 Hz), as such high frequency energy is attenuated, per unit distance through the earth, to a greater extent than is low frequency energy. Since the resolution increases with the bandwidth of the energy used, the resolution achievabl according to the present invention is much improved from conventional surface-based, or MWD-type, surveys.

It is recognized that the detection of high frequency energy provides a large amount of data in short periods of time. In addition, according to the present invention, this large amount of data may be handled in alternative fashions. According to a first alternative, the energy detected by detectors 20 is communicated as raw data to the surface. This may be accomplished by high speed telemetry equipment having a transmitter downhole within data handling unit 40, which communicates the raw detected data along drill string 10 to the surface, such as to sub 24 which contains receivers therewithin. The data is then communicated by hard-wire, or by microwave, radio, or other transmission, to a computer and control center 22, as suggested by Figure 1. Computer and control center 22 is preferably an on-site computer capable of analyzing the data transmitted thereto, as such on-site analysis can provide real-time guidance to the drilling operation, with the direction, weight-on-bit, mud weight and other parameters adjusted according to the analyzed data. Alternatively, the data may be transmitted (or stored and transported) to a remote computing site, for analysis in a non-real-time mode.

Such high-speed telemetry may be accomplished by electrical hard-wired communication within drill string 10. For example, where detectors 20 are piezoelectric transducers of some type, so as to convert mechanical energy into an electrical signal, the output of detectors 20 may be either directly communicated along a wire or cable to the surface, or may be communicated to a downhole sending unit within data handling unit 40 for transmission along a wire or cable to the surface. However, the provision of communication wires and cables in a downhole drilling environment is a difficult task, considering the high temperatures, high pressures; and other conditions (including the mechanical rotation of drill string 10, the

communication of drilling mud therethrough, and the like). As such, while high speed electrical communication along such wires may be used in the present invention, such use is subject to certain limitations.

Therefore, according to the alternative of the present invention in which the energy detected by detectors 20 is communicated in substantially raw form from downhole to the surface, a preferred telemetry technique is the use of modulated vibrations to communicate the same. This communication technique is referred to as stress wave telemetry, and certain techniques and systems for such stress wave telemetry are described in U.S. Patent No. 4,992,997, issued February 12, 1991, assigned to Atlantic Richfield Company and incorporated herein by reference. Examples of preferred stress wave telemetry systems according to the present invention utilize piezoelectric sending transducers which are located within the inner diameter of data handling unit 40, rather than external to the drill string, are described in PCT Publications WO 92/01955 and 92/02054, both incorporated herein by this reference. According to such stress wave telemetry systems, the sending unit in data handling unit 40 vibrates drill string 10 with modulated vibrations at relatively high frequencies, such as on the order of 1000 Hz. The information is communicated by way of frequency shift keying (FSK), phase shift keying (PSK) or other modulation techniques for modulating either axial or torsional vibrations that are applied to drill string 10 at a carrier frequency. Detectors are placed within sub 24 at the surface, such detectors being accelerometers, strain gauges, and the like, for converting the transmitted vibrations into corresponding modulated electrical signals. Demodulation of the modulated electrical signals can then be performed to retrieve the transmitted information from the modulated signal; this information may be transmitted,

either in modulated or demodulated form, to computer and control unit 22 as illustrated in Figure 1. Further detailed description of such a telemetry system will be given hereinbelow.

In the alternative to a piezoelectric transducer, the vibrations and stress waves may be generated by use of a magnetostrictive transducer, utilizing materials such as Terfenol-D which change shape in response to a magnetic field applied thereto. Magnetostrictive transducers may be preferable in some applications, particularly offshore, due to their lower voltage operation as compared with piezoelectric transducers. It is contemplated that provision of a heat conduction path, or other heat dissipation or cooling mechanism, will be preferred in such a transducer, as the I^2R heat may be significant due to the relatively high current required in this technology. The Terfenol-D material and its use in actuators is described in Goodfriend, "Material Breakthrough Spurs Actuator Design," Machine Design (March 21, 1991), pp. 147-150, incorporated herein by this reference.

In the alternative to telemetry of the energy detected downhole according to the present invention, downhole computing equipment may be provided in downhole data handling unit 40 to analyze the data and transmit the results to the surface. The analysis which may be performed downhole is contemplated to range from a thorough and full analysis of the data so that merely an alarm signal may be transmitted to the surface (thereby requiring only low data rate telemetry between data handling unit 40 and the surface), to rudimentary analysis of the data such that intermediate results are transmitted to the surface for completion of th analysis by computer and control unit 22.

As will be described in further detail hereinbelow, modern integrated circuit technology provides high levels of computing power in relatively small single integrated circuit chips. Particularly, numerous digital signal processor integrated circuits, which can digitally analyze analog information such as will be detected by detectors 20 using Fast Fourier Transforms (FFTs), digital filters, and the like, are now commonly available. A preferred architecture for a downhole computer in data handling unit 40 will be described in further detail hereinbelow. The provision of such downhole computing power thus allows for the high data acquisition rates contemplated by the present to be fully utilized to provide high resolution prospecting and formation analysis.

Considering the above alternatives for handling the data generated downhole relative to the prospecting system described herein, data handling unit 40, as it will be used in the description hereinbelow, will refer generically to downhole control, computing and communications electronics necessary to perform the described functions. As is evident from the foregoing, data handling unit 40 may be quite simple, including only that circuitry necessary to communicate the detected energy, and also perhaps to generate the input energy (as in the electromagnetic cases described hereinbelow). Alternatively, data handling unit may include high levels of computing capability (such as will be described in detail hereinbelow) so that the analysis of the data may be performed downhole, reducing the telemetry requirements for communicating the results to the surface. It is contemplated that, considering the functions as described herein, the construction and design of a particular data handling unit 40 will be apparent to one of ordinary skill in the art having reference to this specification.

The ability to utilize downhole-generated and downhole-detected energy, either acoustic or electromagnetic energy, enables high resolution visibility into the volume surrounding the excavation location of the bit. It is contemplated that this ability allows the monitoring of parameters concerning formations through which drilling has taken place, such as velocities and rock mechanics properties; this information can be used to verify or adjust prior surveys and core samples. In addition it is contemplated that the present invention can provide survey information in regions ahead of the bit, and on all sides of the bit. Seismic survey information so provided can include information in both the compressional and shear mode sense, including amplitude and phase analysis; the electrical survey information can be derived from resistivity measurements, as well as AC measurements which transmit and receive electromagnetic energy to detect conductive layers by monitoring the rate of decay of eddy currents therein. Particularly, it is contemplated that the presence and distance away of over-pressurized zones can be determined with relatively high resolution, such that heavy drilling mud and other blow-out prevention actions can be taken as the drilling site becomes near such a zone, rather than forcing such precautions to be taken throughout the drilling operation, where the sole effect of such precautions is to retard the drilling progress.

It is further contemplated that the energy detected by downhole detectors 20 will provide improved monitoring of drilling parameters, including axial and torsional strain and acceleration information, detection of drill string and casing interaction or abrasion, as well as rotating and non-rotating lateral acceleration and bending strain spectra. In addition, it is contemplated that information concerning both wellbore dimension and shape, and drilling mud rheology (including its specific gravity, viscosity,

lubricity, and the like) and pressure, can be obtained by way of the present invention.

The remainder of this specification will describe various approaches to the system of the present invention in further detail. The next following section is directed to data acquisition, and describes examples of both a seismic and an electromagnetic system. Following the data acquisition portion of the specification, data handling will be described in detail, including both a telemetry approach and a downhole computing approach. It should be noted that either of the seismic or electromagnetic data acquisition systems may be used with either of the telemetry or downhole computing options. As a result, the following detailed description is presented by way of example, and is not intended to limit the scope of the invention as claimed.

II. Data Acquisition

A. Look-ahead Seismic Monitoring and Prospecting

According to a first alternative embodiment of a data acquisition method and system, acoustic vibrations are generated and detected downhole, thus providing downhole look-ahead seismic monitoring and prospecting capability.

Figure 2a illustrates, in more detail, the position of detectors 20 within tool 23 according to this embodiment of the invention. Tool 23 is connected as closely as possible to drill bit 15, for example right behind bit sub 19 (and the rear bit stabilizer, if used). Within tool 23, detector 20_0 is located as near as possible to bit 15, preferably within several feet thereof. Detector 20_1, the next nearest detector 20 in tool 23, is preferably

separated from detector 20_0 by at least approximately one-quarter wavelength of the lowest frequency energy of interest. It is contemplated that the seismic energy generated by drill bit 15, and which is of interest for high resolution look-ahead prospecting, is on the order of 100 Hz to 2kHz; as such, the separation between detectors 20_0 and 20_1 is preferably on the order of 7 to 15 feet. An additional detector 20_2 is similarly separated from detector 20_1, by a similar distance.

Tool 23 also includes data handling unit 40 (not shown in Figure 2a for clarity), including data telemetry equipment as will be described in detail hereinbelow, and which may also include downhole computing capability which will also be described in detail hereinbelow. The construction of a single tool 23 which houses detectors 20 and data handling unit 40 is preferred over alternative techniques such as threadably connecting each detector 20 and the data handling unit 40 between drill string sections, as a single tool 23 only requires two couplings, thus providing improved reliability. It is contemplated that the total length of tool 23 may range up to on the order of ninety feet; as such, additional detectors 20 may be deployed therein as desired. The limitation on the length of tool 23 will depend upon the maximum length which the drilling operator can add to the drill string during drilling, as well as on the mechanical strength of tool 23 itself.

Referring now to Figure 2b, the downhole portion of the system will now be described in further detail. Drill bit 15 is in contact with the formation 105 into which drilling is currently taking place. As is well known, particularly as pointed out by the references noted hereinabove relative to the "TOMEX" technology, drill bit 15 imparts seismic energy, in the form of vibrations, into

the earth as it excavates wellbore 101 along the drilling path. This energy is travelling radially away from the location at which drill bit 15 is in contact with the earth, and will be at frequencies, and components (compressional, horizontal shear, vertical shear) which depend upon the drilling operation at each instant.

The seismic energy generated by drill bit 15 travels along various paths in the apparatus, as shown in Figure 2b, with the velocities of the energy depending upon the characteristics of the media of transmission. In addition, as for conventionally generated seismic energy as used in typical surveys, the seismic energy from the bit will be reflected from interfaces and structures at which the instantaneous velocity changes. For example, assuming that stratum 106 of Figure 2b has a different velocity to vibrations from that of stratum 105, reflection of the vibrations generated by drill bit 15 will occur, to some extent, from the interface between strata 105 and 106. According to this embodiment of the invention, detection of the reflected vibrations from this, and other, interfaces will provide information about the distance between drill bit 15 and the interface, as well as information concerning the type of material in stratum 106.

In the alternative to drill bit 15 serving as the seismic source, a seismic, acoustic, or vibrational source may be provided downhole, preferably near drill bit 15, for generating the source energy. Such a dedicated source would allow for selection and control of the amplitude and frequency of the input seismic energy.

The vibrations generated by drill bit 15 and transmitted in its envir nment will likely manifest themselves at locations along drill string 10 in several forms. Referring to Figure 2b, detector 20_0 is located near

drill bit 15, as noted above relative to Figure 2a. According to this embodiment of the invention, it is preferred that each detector 20 be capable of detecting acceleration, strain, and pressure changes in the drilling fluid surrounding detector 20. This will allow comparison of the types of information received at approximately the same time by detectors 20, which may also be indicative of the surroundings, and which may be useful in separating signal from noise.

Referring now to Figures 3a and 3b, a preferred embodiment of detector 20 will be described in further detail. Detector 20 contains the appropriate apparatus for detecting energy in the form of acceleration, strain, and fluid pressure; the acceleration and strain energy is detectable in varying directions according to this construction of detector 20.

The accelerometer and strain gage system in detector 20 is functionally similar to that described in the above-referenced and incorporated U.S. Patent No. 4,992,997, issued February 12, 1991, and U.S. Patent No. 4,715,451, issued December 29, 1987, both assigned to Atlantic Richfield Company. In the example illustrated in Figure 3a, detector 20 corresponds to a portion of tool 23, through which drilling mud may pass from the surface to drill bit 15 in the conventional manner. At the location of detector 20, protective cover or liner 68 is disposed within the interior of tool 23 to cover a portion of the interior walls 27 thereof from drilling mud passing therethrough. Located within the space provided by liner 68, and attached to walls 27 of tool 23, are accelerometers 70, 72, 74 and 76. Accelerometers 70, 72, 74, 76 are preferably of conventional construction for high resolution acceleration detection, as described in U.S. Patent No. 4,715,451, with their axes of sensitivity directed in

varying directions, such that acceleration energy communicated along drill string 10 in different directions may be detected, and eventually compared. For example, the accelerometers may be arranged so as to detect torsional or bending vibrations on drill string 10. This may be accomplished by orienting the axis of sensitivity of accelerometers 72 and 74 to sense acceleration in a direction which is in a plane normal to the axis 17 of drill string 10. Accelerometers 70 and 76 may have their axes of sensitivity oriented in such a manner as to each sense motion along axis 17 of drill string 10, but in opposite directions relative to one another; as a result, not only can detector 20 detect axial acceleration, but bending vibrations may also be detected, as bending vibrations would cause out of phase from accelerometers 70, 76.

Detector 20 further includes a system of strain gauges 78, 80, 82, 84 mounted to the interior surface of walls 27, and within protective liner, for detection of strain on drill string 10 (i.e., stress wave vibrations traveling along drill string 10 through detector 20). Strain gauges 78, 80, 82, 84 are conventional strain gauges, for generating an electrical signal or impedance according to the mechanical stress applied thereto, and are also preferably arranged within detector 20 in order to detect such stress wave vibrations which are of different directional components, i.e., both axial and torsional stress wave vibrations. It is contemplated that the illustrated arrangement of Figure 3a is by way of example only, and that other arrangements of accelerometers, strain gages, and the like may alternatively be deployed at detector 20, optimized for the type of energy expected.

Also included in detector 20 according to this embodiment of the invention, in addition to the detection

equipment described in the above-referenced U.S. Patent No. 4,992,997 and U.S. Patent No. 4,715,451, are pressure transducers 71, 73, 75, mounted in such a manner as to be in contact with drilling mud or fluid within wellbore 101. Pressure transducers 71, 73, 75 (and another transducer not shown, which is on the opposite side of detector 20 from transducer 75), are preferably flush-mounted along the outside surface of walls 27 with their direction of sensitivity in a radial direction from the axis of tool 23. Each of pressure transducers 71, 73, 75 are for detecting fluid pressure on its side of tool 23, and for converting the mechanical energy of such pressure into an electrical signal. The orientation of the multiple pressure transducers 71, 73, 75 allows for monitoring the pressure coming from various directions, which will provide positional information relative to the source of such energy (or reflections of such energy).

Referring to Figure 3b, a portion of tool 23 is illustrated in cross-section illustrating the position of four protective liners 68 for isolating the instruments of detector 20. Passageway 29 is provided between protective liners 68, to allow the passage of drilling fluid therethrough.

Each of the accelerometer, strain gauge, and pressure transducer components of detector 20 generates an electrical signal (directly, or by way of an impedance) according to the particular physical energy to which each responds. These electrical signals are communicated to data handling unit 40 located within and at the location of tool 23, for communication directly to the surface by way of hardwired telemetry, stress wave telemetry, or the like, or for analysis by d wnhole computing equipment with the results transmitted by telemetry therefrom. The data handling and communication useful with this embodiment of

the invention is noted hereinabove, and will be described in detail hereinbelow.

As noted hereinabove, it is contemplated that the distance between drill bit 15 and the its closest detector 20_0 will be relatively short, for example on the order of less than ten feet; this is relatively close, considering that the depth of many modern wells can easily be on the order of thousands of feet. Also as noted hereinabove and as will be described in further detail hereinbelow, for purposes of noise reduction and analysis, it is preferred that multiple detectors (or detectors) 20 be provided along drill string 10, separated from one another by a particular distance. The distance of separation may be optimized according to the resolution necessary for the noise reduction or data analysis; it is contemplated that the separation between detectors 20 will preferably be at least one-quarter wavelength of the lowest frequency signal component.

It should also be noted that detectors 20 may be advantageously deployed in groups, one group at each location along wellbore 101. The vibrations from each of the detectors 20 in such a group may be averaged together, so that vibrations of certain wavelengths are eliminated. This technique is similar as that used in making geophone spreads in surface seismic prospecting, to remove the effects of "ground roll".

Figure 2b illustrates the different paths 30, including both direct and reflected, which exist for the travel of energy between drill bit 15 and detector 20. Path 30a is a direct path between drill bit 15 and detector 20, where the vibrations travel through drill string 10 therebetween. Path 30b is also a direct path of vibrations from drill bit 15 to detector 20, where th surrounding

formation 105 is the transmission medium. Path 30c is another direct path for the vibrations from drill bit 15 to detector 20, where drilling fluid in wellbore 101 is the medium. It should be noted that path 30b for vibrations where surrounding formation 105 is the transmission medium is of interest, as seismic velocity measurements may be made therefrom, as will be discussed hereinbelow.

The reflected paths of the vibrations from drill bit 15 to detector 20 are especially of interest as they are indicative of the presence and depth of formation 106 ahead of drill bit 15. Path 30d illustrates the path followed by vibrations from drill bit 15 as they pass through formation 105 to the interface with formation 106, reflect back to drill bit 15, and travel to detector 20 along drill string 10. Path 30e is the path followed by vibrations from drill bit 15 through formation 105 and reflected from formation 106, where formation 105 is the transmission medium for the reflected vibrations to detector 20. Path 30f is that followed by vibrations from drill bit 15 through formation 105 and reflected from formation 106, where the reflected vibrations travel back through formation 105 to the drilling fluid in wellbore 101, and reach detector 20.

It is contemplated that these six paths will each transmit vibrations from drill bit 15 of sufficient magnitude to be detectable by detector 20. Referring now to Figure 4, the temporal relationship of the detected vibrations will now be discussed, relative to the example of an impulse vibration from drill bit 15 of Figure 2b, It is of course understood that the vibrations of drill bit 15 in an actual drilling environment will seldom consist of a series of pure impulses with wait times between each. Accordingly, while the example of an impulse input is presented herein for purposes of explanation, it is contemplated that conventional correlation techniques may

be used to determine the various travel times shown in Figure 4. Correlation and stacking techniques used in conjunction with the above-noted "TOMEX" system are contemplated to be especially useful, since the "TOMEX" system also uses the drill bit as the seismic energy source.

Figure 4 illustrates a set of time plots of such energy, illustrating the time required for the energy to travel the various paths, showing both pressure and strain characteristics. Trace (a) in Figure 4 corresponds to strain vibrations detected by strain gauges 78, 80, 82, 84 in detector 20, as described hereinabove relative to Figure 3a, while trace (b) in Figure 4 corresponds to pressure measurements made by pressure sensors 71, 73, 75. The acceleration measurements made by accelerometers 70, 72, 74, 76 will also have importance in this method.

In Figure 4, the impulse vibrations are generated by drill bit 15 at time t_0. Since the highest velocity path in the example of Figure 2b is the direct path 30a through drill string 10 (velocity on the order of 16,850 ft/sec), the first vibrations detected by detector 20, at time t_a, are those which traveled along path 30a. The vibrations traveling directly along path 30a in drill string 10 from drill bit 15 to detector 20 can be considered as the source signature for purposes of correlation, in a manner similar to the "TOMEX" system noted hereinabove, but detected at a location much nearer drill bit 15. Since the distance between drill bit 15 and each detector 20 is known, and since the velocity of vibrations in drill string 10 is known, the time relative to time t_0 for each arrival of detected vibrations via path 20a can be readily calculated.

The next vibrations detected, at time t_b of Figure 4, are those which traveled along direct path 30b, where

formation 105 is the transmission medium. This is because the velocity of vibrations along path 30c through the drilling fluid in wellbore 101, arriving at detector 20 at time t_c in Figure 4, has a value (e.g., on the order of 5000 ft/sec) significantly less than the velocity of most commonly-encountered formations (e.g., on the order of 8000 ft/sec). It should be noted that comparison of the time difference between times t_b and t_a will provide an indication of the seismic velocity of the surrounding formation 105.

Any reflected vibrations from formation 106 ahead of drill bit 15 will reach detector 20 at significantly later times, as the paths 30d, 30e, 30f of such vibrations each include twice the distance between drill bit 15 and formation 106. In Figure 4, times t_d, t_e, and t_f correspond to detected vibrations which follow paths 30d, 30e, and 30f, respectively. Since each of the reflected paths 30d, 30e, 30f include approximately the same two-way distance (in addition to the length and medium of its analogue path 30a, 30b, 30c, respectively), the vibrations will reach detector 20 in approximately the same order as the corresponding direct vibrations (the time differences among paths 30d, 30e, 30f corresponding to the differences in media velocity for the various paths between drill bit 15 and detector 20). While it is contemplated that, for path 30f, the vibrations will couple into the drilling fluid at the bottom of wellbore 101 with greater efficiency than elsewhere along the length of wellbore 101 so that a distinct vibration will be detectable at time t_f, it is understood that those reflected vibrations will couple into the drilling fluid along the entire length of wellbore 101 between drill bit 15 and detector 20. As a result, depending upon the coupling efficiency, the detected peak at time t_f may be less distinct in actual practice than that shown in Figure 4.

The first of the reflected vibrations to reach detector 20, at time t_d, are those traveling along path 30d, i.e. reflected from formation 106 and traveling to detector 20 along drill string 10. The time difference between time t_d and time t_a will be substantially the "two-way" time from drill bit 15 to formation 106; knowing the velocity of formation 105 therebetween thus can give an indication of the depth between drill bit 15 and formation 106. The other reflected vibrations received at times t_e and t_f similarly can provide two-way times, when compared against their direct path analogues (times t_b and t_c, respectively).

Furthermore, it is contemplated that other attributes of the vibrations detected by detector 20 will provide additional information regarding the presence, depth and attributes of formation 106. For example, it is well known that the phase of a reflected wave depends on the relative acoustic velocities of the transmitting and reflecting media. Accordingly, phase comparison of the sensed reflected vibrations (i.e., those received at times t_d, t_e, t_f) with their direct analogues (at times t_a, t_b, t_c, respectively) can provide an indication of the relative velocities of formations 105, 106.

Comparison of the vibrations detected by strain gauges 78, 80, 82, 84 in detector 20, with those detected by accelerometers 70, 72, 74, 76 also can provide important information concerning the drilling process. It is contemplated that the ratio of strain to acceleration corresponds to the extent of the coupling of drill bit 15 to formation 105 into which it is drilling, as a greater strain level for a given acceleration force would indicate that drill bit 15 is in contact with formation 105 with greater force, and that formation 105 is relatively hard. A reduced amount of strain for the same level of

acceleration would, on the other hand, indicate that drill bit 15 is either not firmly in contact with formation 105, or that formation 105 is a relatively soft formation.

As shown in Figure 3a, the construction of detector 20 according to this preferred embodiment of the invention has pressure sensors 71, 73, 75 (and 77, not shown) facing in four directions radially from the axis of drill string 10; as a result, pressure sensors 71, 73, 75, 77 are arranged in pairs of diametrically opposing sensors. For example, sensors 71 and 73, diametrically oppose one another but are at the same depth. Comparison of their detected vibrations may be indicative of the type of vibration detected. For example, if the vibrations detected at the same time by sensors 71 and 73 are in phase with one another, the vibrations are likely to be pressure waves. If diametrically opposite sensors 71, 73 detect vibrations which are opposite in phase, the vibrations are likely to be horizontal shear waves.

The ability to distinguish pressure waves from shear waves is important as it provides additional information concerning the sub-surface geology. As is well known in the art, the ratio of the pressure wave velocity to the shear wave velocity depends upon the composition of the medium through which the vibrations are transmitted. In the case of detector 20 with diametrically opposed pressure sensors 71, 73 (and 75, 77) as described hereinabove, the difference in the velocities will be manifested as discrete detection of vibrations at different times; since pressure waves generally have a higher velocity than shear waves, the in-phase detected vibrations will be seen first, with the out-of-phas detected vibrations seen later. As noted hereinabove, time t_0 at which the vibrations are generated by drill bit 15 can be readily determined from the first arrival of detected vibrations at detector 20 via path 20a,

as the distance and velocity are known. Accordingly, the pressure wave velocity and shear wave velocity of formation 105 in this example can be readily determined from the time delay from time t_0 to the arrival time of the direct vibrations of each component along path 20b. Calculation of the ratio of these velocities can then be readily calculated, providing further information regarding formation 105. Furthermore, detection of this shear mode would be particularly useful in horizontal wells, as refracted shear wave detection could be used to locate vertical distances within a substantially horizontal formation.

As is well known, significant vibration in drill string 10 is generated during the drilling of a hydrocarbon well. This vibration of course includes the rotation of drill string 10 itself for surface-drive drilling rigs such as shown in Figure 1. While the average rotation rate of drill string 10 is known from the surface drive, and is useful for filtering out vibrations at the frequency of rotation and its harmonics, it is preferred that a magnetometer be located near drill bit 15 to sense its instantaneous orientation and frequency of rotation, and to generate an electrical signal accordingly. This allows for bit effects such as "stick-slip" to also be taken into account in noise reduction and in the monitoring of bottom-hole assembly dynamics. This electrical signal can be provided to downhole sending unit 40 for communication to the surface, or included in the downhole calculations, as appropriate.

Referring back to Figure 1, it is preferred that multiple detectors 20 be located along the length of drill string 10. For example, four to six detectors 20 (or groups) may be spaced along the length of drill string, particularly along the lower part thereof. Such multiple

detectors are believed to be quite useful in connection with this embodiment of the invention, due to the large amount of noise generated during the drilling operation.

Significant noise is generated in the drilling of a well generated by the rotation of drill string 10 in a surface-drive arrangement, as noted above; where a downhole motor is used to turn drill bit 15, vibrations relating to the rotation of the drill bit will also be generated that correspond to the rotation of drill bit 15, and which will appear as coherent noise. Vibrations are also generated by the drilling fluid as it is pumped through drill string 10 at high pressure. Other apparatus in the drilling operation, such as bearings in the swivel 21 at the top of the drill string, the rattling of chains which turn the kelly bushing, and the slap of drill string 10 against the casing or against wellbore 101, also generate significant acoustical vibrations which are received by and transmitted along drill string 10. Each of these vibrations are superimposed upon the vibrations generated by drill bit 15, as detected by each of detectors 20 in the system. Since it is the vibrations from paths 30 of Figure 2b which are of interest (i.e., the "signal"), these other vibrations constitute noise for purposes of this analysis.

It should be noted that much of these noise vibrations are generated at a point along drill string 10 above detectors 20. For the system of Figure 1, where vibrations generated by drill bit 15 constitute the signal, the down-going noise vibrations will reach detector 20_1 before they reach detector 20_0. Conversely, the vibrations generated by drill bit 15 as described above will reach detector 20_0 before they reach detector 20_1. Comparison of the detected vibrati ns from the various locations 20_0 and 20_1, by way of "stacking" or other correlation techniques, can thus allow one to distinguish up-going vibrations (the "signal")

from down-going vibrations (the "noise"). Similar noise reduction has been done in the marine environment, and is commonly referred to as "de-ghosting", where down-going reflections from the water surface are subtracted from the detected signal so that the portion of the detected vibrations corresponding to up-going reflections from sub-surface geology is enhanced. Accordingly, the provision of multiple detectors 20 along the length of drill string 10 can allow for reduction of noise generated above detectors 20.

As noted hereinabove, numerous advantages are made available from this embodiment of the invention, whether the data is communicated in substantially raw form to the surface, or is analyzed by a downhole computer (each alternative described in further detail hereinbelow). The resolution of the data obtained by the downhole detection of seismic vibrations generated downhole, such as from drill bit 15, can be significantly greater than that obtained from conventional surface prospecting methods, and also than that from the surface detection of drill-bit generated vibrations (such as is used in the "TOMEX" method described hereinabove). In each of these prior techniques, the frequency of the seismic energy is necessarily quite low (less than 100 Hz) due to the attenuation of higher frequency vibrations in traveling from downhole to the surface. According to the present invention, however, the downhole location of detectors 20 reduces the distance that the vibrations must travel through the earth (particularly for reflected vibrations traveling along path 30d, where drill string 10 is the medium), and thus reduces the attenuation of higher frequency vibrations. It is contemplated that vibration frequencies on the order of hundreds or thousands of Hz can be analyzed according to this method, thus providing seismic information with resoluti n on the order of one meter.

The survey information provided by this method not only has higher resolution, but may be acquired during the drilling operation itself to obtain real-time high resolution information about formations ahead of the bit. Particularly, overpressurized zones ahead of drill bit 15 can be detected, and their distance away from drill bit 15 determined. This allows for the use of heavier drilling mud only as the drilling operation approaches, allowing for lighter drilling mud to be used along a greater length of the wellbore drilling operation. In addition, a better estimate of the required mud weight can be made using this method, allowing for the proper casing design, and reducing the possibility of formation damage. Safety from blow-outs can thus be obtained without greatly affecting the efficiency of the operation.

Furthermore, the high resolution survey information acquired during drilling according to this method can allow for real-time adjustment of the drilling operation, particularly in direction, so that the likelihood of reaching a hydrocarbon reservoir increases. Particularly, information about the sub-surface formations through which drilling has occurred, for example velocity information (pressure and shear) can be used to verify or adjust prior conventional surveys of the drilling site. In addition, information concerning the formations ahead of the bit can also be acquired, further supplementing the prior surveys and allowing for adjustment of the drilling direction, speed, and the like.

The use of multiple detectors 20 along the length of tool 23 according to this embodiment of the invention also allows for the detection and characterization of offset formations, i.e., those formations which have a surface which is substantially parallel to the borehole. If, for

example, the time difference between reflected waves detected by separate detectors 20 is much smaller than that which would occur from a formation ahead of drill bit 15 (due to the distance along tool 23 between detectors 20), one can deduce that the path lengths of the two reflections are relatively close. Using an analysis technique similar to "beam forming" in the surface seismic surveying art, the distance and characteristics of such an offset formation may be determined using this embodiment of the invention.

As a by-product of the method according to this embodiment of the invention, the vibrations detected downhole by detectors 20 may also be used to monitor the drilling process itself, such as by monitoring weight-on-bit, bottomhole assembly strain, bit-to-earth coupling, and other parameters of importance to the drilling operator. Conditions such as washouts, stick-slip, and the rate of fatigue (i.e., the absolute number of cycles) can also be monitored.

Other advantages of this embodiment of the invention should also now be apparent to one of ordinary skill in the art having reference to this specification.

B. Look-ahead Electromagnetic Monitoring and Prospecting

According to alternative embodiments of a data acquisition method and system, electromagnetic energy is generated and detected downhole for look-ahead monitoring and prospecting. Two alternative embodiments using electromagnetic energy which is both generated and sensed downhole will be described in detail hereinbelow. These two techniques will be referred to as galvanic and induction methods, respectively.

1. Galvanic Electromagnetic Look-ahead Data Acquisition

Referring now to Figure 5, downhole tool 23g for galvanic electromagnetic look-ahead monitoring and prospecting system will now be described in detail, relative to a drilling operation. Tool 23g is preferably connected on one end to bit sub 19 so as to be as near to drill bit 15 as practicable. On its other end, tool 23g is connected to drill string 10. As noted hereinabove relative to the look-ahead seismic case, tool 23g may be on the order of up to ninety feet in length; the diameter of tool 23g is on the order of that of drill string 10 and bit sub 19.

Tool 23g includes several electrodes 51, 52, 53, 54 along its length, with which the galvanic measurements will be made. Electrodes 51, 52, 53, 54 are in electrical contact with drilling fluid in the annulus of wellbore 101 surrounding drill string 10, and thus are electrically coupled to formation 105 surrounding wellbore 101 at the location of tool 23g. Alternatively to electrical connection via drilling fluid, electrodes 51, 52, 53, 54 may be in direct contact with surrounding formation 105 by way of shoes or other contacts extending outwardly from tool 23g. Further in the alternative, electrodes 51, 52, 53, 54 may be discrete electrodes or sets of electrodes, rather than bands around the circumference of tool 23g as shown in Figure 5.

Electrode 54, which is nearest bit sub 19, is disposed between two insulating sections 50 of tool 23g. Each insulating section 50 preferably is formed of a glass-mica composite, epoxy fiberglass, or another one of the ceramic materials known in the art to be capable of withstanding

the high temperature and hostile downhole environment. Accordingly, electrode 54 is electrically insulated from bit sub 19 and from the portion of tool 23g thereabove. Electrode 54 is preferably as close as possible to bit sub 19, for example on the order of one to two feet away therefrom.

Electrodes 51, 52, 53 are located varying distances away from electrode 54 along tool 23g. For the example of Figure 5, electrode 53 is preferably located approximately 1/4 the length of tool 23g from its bottom end, electrode 51 is preferably located approximately 2/3 the length of tool 23g from its bottom end, and electrode 52 is preferably located between electrodes 51 and 53, but near to electrode 51, for example on the order of three feet away therefrom. Each of electrodes 51, 52, 53 are also insulated on both sides by insulating material 50.

The two other "electrodes" used by tool 23g are drill string 10 itself, which is insulated from tool 23g by an insulating section 50 located at the top end of tool 23g, and bit sub 19. The length of the electrode of drill string 10 will be quite long, up to hundreds of feet long for a conventional well. Drill string 10 and bit sub 19 will source the electrical current into the earth, and as such are electrically connected to a controllable power source.

The source of power for drill string 10 and bit sub 19, as well as other electronic circuitry for detecting voltages and currents downhole and either transmitting or computing the same, noted above and as will be described hereinbelow, are preferably located within tool 23 itself, for example in data handling unit 40 (not shown in Figure 5 for clarity). Alternatively, the power source and other circuitry may be provided within a special sub threadedly

connected within drill string 10. In either case, the power source and other circuitry is preferably mounted in such a manner that drilling fluid may continue to flow from the surface from drill string 10 to drill bit 15 in the conventional manner. Alternatively, the driving and measurement circuitry may be provided at the surface, with hardwired connection to the various locations of drill string 10 and electrodes 51, 52, 53, 54 to make the measurements described hereinbelow. Other techniques for generating the desired current and making the below-described measurements will, of course, be apparent to those of ordinary skill in the art. Voltmeter 55 measures the voltage V_3 between electrodes 51 and 52, voltmeter 56 measures the voltage V_2 between electrodes 51 and 53, and voltmeter 58 measures the voltage V_1 between electrodes 51 and 54.

Figure 5 also illustrates, schematically, the various current paths and voltages used in, and the operation of, the system incorporating tool 23g according to this embodiment of the invention. A current source is provided which sources current into the earth between drill string 10 and bit sub 19. It is preferred that current I_s will be generated at a relatively low frequency, for example less than 1 kHz, and preferably in the tens of Hz, so that eddy currents in drill string 10 are avoided.

Current meter 57 measures current I_s, and voltmeter 59 measures the corresponding voltage V_s between drill string 10 and bit sub 19. The ratio V_s/I_s corresponds to the contact resistance of drill string 10 and bit sub 19, which will be largely dependent upon the resistance of the contact between the earth, on the one hand, and drill string 10 or bit sub 19, on the other hand. As noted hereinabove, the various meters 55, 56, 57, 58, 59 and the others are preferably provided within tool 23g. Similarly

as noted hereinabove for the look-ahead seismic prospecting case, the raw output of meters 55, 56, 57, 58, 59 may be communicated directly to the surface by hardwire, or to a downhole data handling unit 40 (Figure 1) for transmission to the surface by way of stress wave telemetry, mud pulse telemetry, magnetostrictive telemetry, or other techniques. Alternatively, downhole computing power may be provided within downhole data handling unit 40, so that the outputs of meters 55, 56, 57, 58, 59 are communicated to the downhole computer, with the result of the computation then transmitted to the surface.

Each of the voltages V_1, V_2, V_3 are indicative of the current density and resistivity of the formation surrounding tool 23g, with the measured voltages V_1, V_2, V_3 measuring the voltages from different volumes of the formation, and different depths of investigation, due to their location along tool 23g, particularly their proximity to bit sub 19. Similarly as in conventional logging tools, the depth of investigation of voltage V_1 between electrodes 51 and 54 is relatively shallow, for example on the order of one foot, due to the short distance between the electrode of bit sub 19 and electrode 54. The depth of investigation for electrode pair 51, 54 is shallow since the current density is quite concentrated within the volume near bit sub 19. Accordingly, conductive formations or other structures away from tool 23g will have little effect on the voltage V_1 measured between electrodes 51 and 54. The resolution of the measurement made by electrodes 51, 54 will be quite fine, however.

Conversely, voltage V_3 between electrodes 51 and 52 according to this embodiment of the invention will have a very large depth of investigation. This is because the density of the current I_s through the formation that surrounds tool 23g is lower at locations away from bit sub

19 than at locations near thereto. Accordingly, changes in the conductivity of surrounding formations some distance from tool 23g will affect the voltage V_1 measured by electrode pair 51, 52. The length of drill string 10 above tool 23g assists in the distribution of current I_s in such a manner that a significant portion thereof will travel through the earth ahead of bit sub 19, as suggested in Figure 5.

For example, Figure 5 illustrates formation 106 which is some distance ahead of bit 15, which is currently within formation 105. If, for example, formation 106 is significantly more conductive than formation 105, the current density near electrodes 51 and 52 will decrease, since a greater portion of the current passes through conductive formation 106 than if the geology were homogenous. In effect, the resistance of formation 105 in the volume near electrodes 51, 52 is effectively in parallel with a lower resistance when drill bit 15 (and tool 23g) is near a conductive formation. A drop in the measured voltage V_1 will thus be detected; since electrode 54 is near bit sub 19, and since most of the current I_s is concentrated near electrode 54, little, if any, drop in voltage V_1 will be detected.

Conversely, drill bit 15 approaches formation 106 which has significantly less conductive than formation 105 (for example, if formation 106 is a hydrocarbon reservoir), the current density in the volume near electrodes 51 and 52 will increase over that in the homogeneous case, and the voltage V_3 measured by electrodes 51 and 52 will increase. This situation is analogous to a parallel resistor network which has a resistor with relatively low resistance replaced with one having a higher resistance, raising the resistance of the parallel resistor network. As in the

prior case, due to the close proximity of electrode 54 to bit sub 19, little effect on voltage V_1 will be detectable.

Measurement of voltage V_2 between electrodes 51 and 53 provides a depth of investigation between that of the other electrode pairs 51, 52 and 51, 54, as electrode 53 is between electrodes 52 and 54. Accordingly, tool 23g of Figure 5 provides the ability to acquire measurements of varying depths of investigation, from contact resistance V_s/I_s to the look-ahead measurement of V_3.

Referring now to Figure 6, the operation of a method of interpreting the results of the measured voltages V_1, V_2, V_3 will now be described. Figure 6 is an example of a log of a resistivity measurement ρ_m, based upon one of the measured voltages, for example voltage V_3 which has a large depth of investigation, versus the depth of drilling z; the resistivity ρ_m may be obtained by dividing the measured voltage (in this case V_3) by a current value based on the measured source current I_s. During the drilling operation, the resistivity value ρ_m changes with the various formations encountered. Either within the downhole data handling unit 40, or at the surface, a history of the measurements of ρ_m are stored. Based upon these measurements, and according to a weighted sum or other algorithm, a statistical distribution for the expected resistivity value ρ_m at depth z_x may be calculated, assuming that the current formation into which drill bit 15 is drilling is infinitely deep (i.e., the geology is homogenous ahead of drill bit 15). It should be noted that this expected resistivity value may differ from that of the immediately prior measurement (i.e., it is not a good assumption that the most recent resistivity value will continue), as the varying resistivity of prior formations will also affect the measured value, particularly for the measurement having a large depth of investigation.

At depth z_x of drill bit 15, the computing equipment compares the measured resistivity value ρ_m is compared against the calculated expected value ρ_{calc}. A statistically significant deviation between the measured resistivity value ρ_m and the calculated expected value ρ_{calc} is indicative of an approaching change in formation ahead of drill bit 15. For example, a measured resistivity value ρ' which is significantly lower than the value ρ_{calc} indicates a high conductivity formation ahead of drill bit 15; conversely, a measured resistivity value ρ' which is significantly higher than the value ρ_{calc} indicates a low conductivity formation ahead of drill bit 15.

The technique illustrated in Figure 6 may also incorporate knowledge from previously acquired stratigraphic surveys, in the alternative to calculating the expected resistivity value ρ_{calc} assuming that the current formation extends infinitely deep from the current location z_x. For example, based on prior surveys, on the known bit depth, and modified by previously measured resistivity measurements ρ_m, the expected value ρ_{calc} may be determined assuming the presence of a new formation with an assumed conductivity at a particular depth in advance of drill bit 15. Deviations between the actual measured resistivity ρ_m and this calculated resistivity will then indicate deviations between the depth or conductivity of actual formations in the earth and that of the survey.

Figure 6 plots resistivity versus depth for one of the measured voltages (e.g., V_3). The plots of Figures 7a and 7b illustrate the information that can be obtained from a comparison of the multiple voltages measured by tool 23g as illustrated in Figure 5. Figure 7a is a plot of three resistivity measurements ρ_1, ρ_2 and ρ_3 versus depth z, based on the three voltage measurements V_1, V_2, V_3, respectively,

which are obtained by tool 23g of Figure 5. In Figure 7a, depth z corresponds to the depth of drill bit 15, with each of the three resistivity measurements ρ_1, ρ_2 and ρ_3 taken at the same position.

In the example of Figure 7a, depth z_i is a depth at which drill bit 15 enters a new formation which is significantly more conductive formation; referring to Figure 5, depth z_i is the depth at which drill bit 15 will first touch formation 106. Resistivity ρ_{act} is a plot of the actual resistivity of the formations encountered by drill bit 15. At drill bit depth z_x (which is above the interfacial depth z_i, for example with drill bit 15 in the position shown in Figure 5), Figure 7a illustrates that the resistivity ρ_3 which is based on voltage V_3 between electrodes 51 and 52, and which has the deepest depth of investigation, is lower by a larger degree than the other measurements ρ_2 and ρ_3 from electrode pairs which have shallower depths of investigation.

Figure 7b is a comparison plot of the resistivity measurements ρ_1, ρ_2 and ρ_3, for drill bit depth z_x above the interfacial depth z_i, versus distance d of the corresponding electrodes 54, 53, 52 above bit sub 19. Resistivity ρ_1 is the highest value, with resistivity ρ_2 lower due to the approaching conductive formation, and with resistivity ρ_3 the lowest of the three due to its deeper depth of investigation. It is contemplated that a comparison of the three resistivity measurements ρ_1, ρ_2 and ρ_3 can be used to calculate the distance (z_i-z_x) which the new formation 106 is ahead of drill bit 15, such calculations being analogous to "soundings" by which the depth of a body of water is calculated based on sonar measurements.

It is contemplated that other uses and calculations of resistivity, depth, and comparisons f the same to

previously obtained stratigraphic surveys will now be apparent to those of ordinary skill in the art having had reference to the foregoing.

As a result of this embodiment of the invention, it is contemplated that the presence of an approaching formation may be detected ahead of drill bit 15. It is particularly contemplated that high conductivity formations, such as hydrocarbon reservoirs, may be so detected. It is further contemplated that this system and method may be used in order to detect the presence of an overpressurized zone ahead of the bit by some distance, such that corrective action may be taken prior to the drill bit 15 reaching the overpressurized zone. For example, lightweight drilling mud may be used for much of the drilling operation, thus providing for fast and efficient drilling; upon detection of a lower resistivity layer ahead of the drill bit, such lower resistivity indicating an over-pressurized zone, heavier drilling mud may then be pumped into wellbore 101, preventing a blow-out condition from occurring. Such knowledge about the proper mud to be used can also allow for optimized casing design.

In addition, it is contemplated that this method will also provide for a real-time resistivity log, with the data acquired during the drilling of the well. In particular, the data acquired according to this method will not only be a local resistivity log, extending in a plane perpendicular to the wellbore as in conventional MWD resistivity logging, but also gathers bulk resistivity information, including resistivity of layers ahead of the drill bit. The resistivity data so acquired can be compared against prior information, such as that acquired from neighboring wells, seismic surveys, and the like, to provide a more accurate survey, and to adjust prior surveys to match the attributes measured during drilling.

2. Electromagnetic Induction Look-ahead Data Acquisition

Referring now to Figure 8, a downhole electromagnetic induction look-ahead monitoring and prospecting system will now be described in detail. As will be apparent from the following description, this system generates magnetic fields which induce eddy currents into surrounding conductive formations. These eddy currents in turn generate magnetic fields which induce currents in a coil located in the downhole portion of the drill string; this coil may be the same coil as that which generated the magnetic field, or may alternatively be a separate coil therefrom. In the alternative to an induction coil, a high resolution AC-coupled magnetometer may be used to detect magnetic fields generated by these eddy currents. It is contemplated that measurement and analysis of the induced return current will be indicative of the presence, distance, and characteristics of conductive layers ahead of the drill bit.

Figure 8 illustrates the downhole portion of a drill string 10 which has drill bit 15 at its terminal end. Bit sub 19 is connected to drill bit 15, and tool 23e according to this embodiment of the invention is connected between bit sub 19 and drill string 10. Insulating bands 60 are provided within tool 23e at a plurality of intervals, such that drill string 10 is insulated from bit sub 19. It is contemplated that the length of drill string 10 will be much longer that of tool 23e together with bit sub 19 and bit 15, particularly for most depths of interest for this embodiment of the invention. Horizontal coil 62h is located within a portion of tool 23e, preferably near bit 19, and will generate and sense magnetic fields having

vertical polar orientation, as the planes of each loop of horizontal coil 62h are perpendicular to tool 23e, and thus substantially perpendicular to the instantaneous direction of drilling. It is contemplated that horizontal coil 62h will be on the order of 100 cm long, having a sufficient number of turns to obtain very high inductance; depending upon the particular configuration, this may require as many as several thousand turns. The terminal ends of horizontal coil 62h are in communication with downhole control and measurement circuitry, for example in data handling unit 40 (not shown in Figure 8) within tool 23e, as discussed hereinabove relative to Figure 1.

Two vertical coils 62v are also located within tool 23e. Vertical coils 62v may be located in another portion of tool 23e which is electrically insulated from the portion within which horizontal coil 62h is disposed, as illustrated in Figure 8. Alternatively, vertical coils 62v may be located at the same location as horizontal coil 62h, for example encircling or within horizontal coil 62h, but electrically insulated therefrom; such construction may be preferred for reduction of the length of tool 23e. Each vertical coil 62v may be on the order of 100 cm long, having a sufficient number of turns to obtain high inductance as noted hereinabove relative to horizontal coil 62h, and is oriented so that the plane of each loop is substantially parallel to the axis of tool 23e, and thus drill string 10, in order to generate and detect magnetic fields having horizontal polar orientation. The individual ones of vertical coils 62v are oriented perpendicularly to one another, to provide detection of the direction of offset formations from tool 23e, as will be noted hereinbelow. Horizontal coil 62h and vertical coils 62v may be energized either in an alternating fashion, or simultaneously, as the magnetic fields generated and

detected by coils 62h, 62v are perpendicular relative to one another.

Figure 9 is a schematic diagram, for purposes of explanation, of a simple implementation of the electronics for generating and sensing magnetic fields from one of the coils 62 (i.e., either horizontal coil 62h or one of vertical coils 62v), as will now be described. Of course, an actual implementation of this system will be somewhat more complex, particularly relative to achieving fast switching times and reduced transient noise. Conventional systems are available for surface electrical geophysics and prospecting which operate similarly as the schematic of Figure 9, and which include such additional circuitry for achieving high performance and sensitivity, and as such would be suitable for use in the present embodiment when configured to operate downhole.

Preferably located downhole with coil 62 (for example in data handling unit 40) is current source 66, voltmeter 68, and switches 67, 69. Current source 66 is connectable by switch 67 in series with coil 62, and is for generating a measurable fixed current through coil 62 to induce a magnetic field in the conventional manner. Resistor 71 is in series with switch 69, so that self-induced currents remain low during the operation of tool 23e; in operation, switch 67 will be open when switch 69 is closed, and vice versa. Switches 67 and 69 allow for coil 62 to both generate and receive magnetic fields, with voltmeter 68 for measuring the voltage received by coil 62 due to the presence of conductive formations. The operation of Figure 9 will be described hereinbelow.

Further reference is directed to U.S. Patent No. 4,906,928, assigned to Atlantic Richfield Company and incorporated herein by reference, which describes a control

system in connection with transient electromagnetic probing ("TEMP") of conductive containers such as pipes. It is contemplated that the techniques in this patent will be applicable to the measurements made by the system of Figure 8.

Magnetometer 64 is also provided within tool 23e, for example above the location of coils 62h and 62v. Magnetometer 64 is a conventional magnetometer having sufficient sensitivity to detect the orientation of drill string 10 relative to the earth's magnetic field. The monitoring of the orientation of drill string 10 by magnetometer 64 allows for cancellation of the earth's magnetic field from the measurements made by coils 62 in tool 23e, and also for synchronizing the rotation of drill string 10 and tool 23e to the measurements made by vertical coils 62v, so that the direction of vertical conductive layers from tool 23e may be determined, as will be noted hereinbelow.

Referring now to Figures 10 and 11 in combination, the operation of electromagnetic induction tool 23e according to this embodiment of the invention will now be described in detail. As shown in Figure 10, drilling of wellbore 101 has progressed into formation 105 which, for purposes of this example, has relatively low conductivity. Ahead of drill bit 15 by some distance is formation 106, which is relatively conductive compared to formation 105; the interface between formations 105 and 106 is substantially perpendicular to wellbore 101. Offset from wellbore 101 is formation 107 which, for purposes of this example, is also more conductive than formation 105 and may also contain hydrocarbons therein; the interface between formations 105 and 107 is closer to being parallel to wellbore 101 than it is to being perpendicular thereto. In this example,

continued drilling of wellbore 101 in the same direction as shown in Figure 10 would miss formation 107.

The operation of this embodiment of the invention will first be described relative to horizontal coil 62h, and its ability to detect formation 106 ahead of drill bit 15. Horizontal coil 62h is first energized by current source 66 (shown in Figure 9), by the closing of switch 67 and opening of switch 69. In the conventional manner, a magnetic field is generated by coil 62h. Referring to Figure 11, at time t=0 switch 67 is opened and switch 69 is closed. The step function decrease in the current through horizontal coil 62h, according to Faraday's law, produces an electromotive force within and outside of horizontal coil 62h. This electromotive force propagates from coil 62h and induces eddy currents in the surrounding structures. These eddy currents have an orientation matching that of the current through coil 62h an instant after time t=0, and as such will behave as distributed horizontal loops throughout the surrounding structure. As is well known in the art, eddy currents decay and physically disperse exponentially, with such decay and dispersal greater in structures having lower conductivity and larger volumes.

Referring to Figures 12a and 12b, the dispersal of these eddy currents will now be described relative to the example of Figure 10 (not considering the effects of drill string 10, which will be discussed hereinbelow). Figure 12a is a contour plot of eddy current density at a point in time after current is no longer being forced through coil 62h, but prior to such time as eddy currents have reached conductive layer 106. At the time illustrated in Figure 12a, dispersal of the eddy currents through relatively non-conductive layer 105 has occurred to a significant degree, and in a relatively uniform fashion from horizontal coil

62h. Figure 12a illustrates this relative to the maxima locations MAX located horizontally outward from horizontal coil 62h. This dispersal and decay occurs at a relatively fast rate due to the relatively low conductivity of formation 105 in this example.

Referring now to Figure 12b, the contour plot of eddy current intensity is now illustrated after such time as the induced eddy currents have reached conductive formation 106. Maxima points MAX now reside in conductive formation 106, and the current density within conductive formation 106 is quite high relative to that in formation 105 surrounding horizontal coil 62h. This is because eddy currents decay more slowly in a conductive layer than in a non-conductive layer, as the decay rate is inversely exponential with conductivity, analogous to the case of an RC electrical circuit. In addition, it is also well known that the dispersal of eddy currents is much reduced in conductive layers rather than in non-conductive layers. As a result, the induced eddy current in formation 105 will continue to disperse, while that in conductive formation 106 will disperse more slowly. It should be noted that the substantially horizontal formation 106 will maintain the eddy current in a horizontal orientation.

Since switch 67 is open and switch 69 closed for horizontal coil 62h according to this example during such time as eddy currents are dispersing in the surrounding formation, horizontal coil 62h will be acting as a receiving antenna. The eddy currents in the surrounding formations 105, 106, and in drill string 10 as will be discussed hereinbelow, will in turn generate a magnetic field. The component of this magnetic field which is coaxial with horizontal coil 62h (i.e., the eddy currents traveling in a plane coplanar with loops in horizontal coil 62h) will induce a current in horizontal coil 62h,

measurable by voltmeter 68. Resistor 71 is preferable in order to minimize the self-induction current in coil 72. As a result, the voltage measured by voltmeter 68 will indicate the time rate of change of magnetic flux due to eddy currents in the structures surrounding horizontal coil 62h. It is contemplated according to this embodiment of the invention that monitoring of this induced current in horizontal coil 62h over time will provide an indication of the presence and distance of conductive structures surrounding coil 62h. Particularly, it is contemplated that the magnetic dipole generated by eddy currents in horizontally oriented formation 106 ahead of drill bit 15 will be detectable by horizontal coil 62h.

As in the embodiments of the invention described hereinabove, various options for handling the detected data may be used, preferred examples of each of which will be described in detail hereinbelow. A first choice is telemetry of the raw measured data, in real-time or otherwise, by way of hardwired telemetry, stress wave telemetry (generated by piezoelectric, magnetostrictive, or other transducers), mud pulse telemetry and the like. Alternatively, downhole computing capability may be provided which receives the raw data and performs some or all of the calculations required in its analysis, with the results of the analysis communicated to the surface by way of telemetry; telemetry of the results may be at a lower data rate than is required for telemetry of high frequency raw data. Downhole electronics corresponding to these approaches may be incorporated into data handling unit of tool 23e, in similar manner as discussed hereinabove. Either of these approaches, as well as others, may be used in connection with this embodiment of the invention.

Referring now to Figure 11, a method for detecting conductive layers distant from horizontal coil 62h will now

be described, relative to its implementation in the system of Figure 9. As described hereinabove, insulating sections 60 are provided within tool 23e itself, and between it and drill string 10. As a result, any eddy currents induced into portions of tool 23e will decay quite rapidly. However, induced eddy currents in drill string 10 will be maintained for some time, and will have a magnetic dipole moment, with a substantial vertical component; the magnetic dipole of drill string 10 will induce a current in horizontal coil 62h.

Figure 11 is a log-log plot of dipole moment versus time, as may be measured by horizontal coil 62h in this embodiment of the invention. For relatively short times after t=0 when the current into horizontal coil 62h is switched off, it is contemplated that the measured magnetic dipole moment will be dominated by eddy currents in drill string 10. In Figure 11, the magnetic field at coil 62h due to drill string 10, in a uniform insulating formation 105, is estimated to behave as line M10. The dominance of the magnetic dipole moment of drill string 10 shortly after the switching time t=0 is due to the proximity of drill string 10 to horizontal coil 62h, as well as its significant length (hundreds or thousands of feet). If drilling is proceeding through a uniformly high resistivity formation 105, it is contemplated that the magnetic dipole moment measured by horizontal coil 62h will substantially follow the decay of the magnetic dipole moment in drill string 10, following line M10 of Figure 11.

It is further contemplated, however, that the presence of a substantially horizontal conductive formation 106 will affect the magnetic dipole moment versus time characteristic measured by horizontal coil 62h. As illustrated relative to Figure 12b, it is contemplated that ddy currents in such a formation 106 will decay and

disperse at a much slower rate in conductive formation 106 than in less conductive formation 105. As a result, it is contemplated that the presence of a conductive formation 106 ahead of drill bit 15 will be evident by a reduced (and perhaps non-linear on the log scale) rate of decay of the magnetic dipole moment over time as measured by horizontal coil 62h. An example of this reduced rate of decay, due to the presence of formation 106, is illustrated as curve M106 in Figure 11, which corresponds to the sum of the effects of drill string 10 and such a conductive formation.

It is further contemplated that the distance of formation 106 ahead of drill bit 15 may also be determined from the magnetic dipole versus time characteristic. For example, time t_a of Figure 11 corresponds to the situation illustrated by the contour plot of Figure 12a, where substantial eddy currents have not yet reached conductive formation 106. Accordingly, the magnetic dipole measured by horizontal coil 62h will be dominated by that of drill string 10, and any effects of conductive formation 106 will not be present (the eddy currents not yet reaching formation 106). Time t_b of Figure 11 corresponds to the situation of Figure 12b, where the eddy currents are maintained near the surface of formation 106, but have substantially dissipated elsewhere. Accordingly, the magnetic dipole moment measured by horizontal coil 62h will not only include the moment of drill string 10, but will also include the dipole moment generated by eddy currents in formation 106, as evidenced by curve M106 in Figure 12. Accordingly, it is contemplated that the time at which the measured magnetic dipole moment deviates from that expected from drill string 10 (and considering that contributed by eddy currents in formation 105 through which drilling is taking place), will be earlier as formation 106 becomes closer to horizontal coil 62h. It is therefore contemplated that analysis of the time at which changes in

magnetic dipole moment are detected, particularly as a function of drilling depth, will provide information regarding the location of a conductive layer.

It is also contemplated that the characteristics of the magnetic dipole moment versus time curve will also provide information about the formation thickness. Figure 11 illustrates dipole moment characteristic M106' which, it is believed, corresponds to the effects of a thin conductive layer ahead of horizontal coil 62h in combination with the effects of drill string 10. As noted hereinabove, eddy currents will be maintained in conductive material for a longer period of time, and decay less, than in non-conductive material. The duration of such eddy currents is of course dependent on the conductivity of the material, but also is dependent on the thickness of the material. Accordingly, a relatively thin layer of conductive material will support eddy currents only for a time corresponding to its thickness, after which the eddy currents will decay and be dispersed in non-conductive material on the opposite side thereof. Curve M106' of Figure 11 illustrates such a case, where the dipole moment is maintained above that of drill string 10 (shown as line M10), but then rapidly falls off until it asymptotically approaches line M10. Detection of this time-related behavior can thus indicate the presence of a thin conductive layer ahead of horizontal coil 62h (and drill bit 15).

The effect of drill string 10 on the detected magnetic dipole moments according to the present invention is believed to be predictable. It is contemplated that either downhole or surface computing capability will be able to readily subtract out these predictable effects, thus improving the accuracy and sensitivity of tool 23e.

Referring back to Figure 9, it is contemplated that vertical coils 62v will operate similarly to detect vertical formations 107 which are distant from wellbore 101. In the same manner as described hereinabove relative to horizontal coil 62h, the energizing and switching off of vertical coils 62v will generate eddy currents in the surrounding structure, but which have a vertical orientation (matching the vertical orientation of loops in vertical coils 62v), and thus a horizontal dipole moment. These eddy currents will disperse and decay in non-conductive material similarly as discussed hereinabove, and will decay and disperse to a lesser extent in conductive material such as a conductive vertical formation 107. The eddy currents which are maintained in vertical formation 107 will generate a magnetic field having a horizontal orientation, and which can therefore be sensed by vertical coils 62v when not energized by its current source. Accordingly, a change in the characteristic of dipole moment measured by vertical coils 62v (relative to the moment generated by eddy currents in drill string 10 and the surrounding formation) can indicate the presence of a conductive formation alongside well bore 101.

Provision of two, perpendicular, vertical coils 62v allows for determination of the direction of formation 107 from tool 23e, even during drilling when drill string 10 is rotating, so long as the orientation of tool 23e can be monitored. Magnetometer 64 is capable of detecting the orientation of tool 23e, such that the measurements from coils 62v can be synchronized with magnetometer 64 so that the direction can be deduced. For example, magnetometer 64 can synchronize the operation of vertical coils 62v in such a manner as to direct the magnetic field in a particular direction; this may be accomplished by controlling the magnitude of the current through each vertical coil 62v, so that the sum of the magnetic field

generated thereby appears (outside of tool 23e) as the equivalent of a single fixed vertical coil oriented in a given direction. Such operation allows for direction of the magnetic field in a selected direction, to determine the presence or absence of a conductive layer in that direction. Iterative rotation of the direction in which the fields are generated through 180° will provide full coverage of the volume of interest.

This technique of rotating the direction of interest can determine the direction of an formation which is offset from tool 23e. However, ambiguity in the detected direction will remain, as the two coils are unable to distinguish perfectly vertical offset formations which are diametrically opposite from one another. However, it is contemplated that the use of prior history will allow the distinction of even this ambiguity, as the direction of the interface from the normal will provide differing magnitudes over time. Any deviation, over depth, in the angle of the interface from that which is exactly parallel to tool 23e will provide the ability to fully identify the direction of formation 107 from tool 23e, using previously obtained information during the same drilling operation. By knowing the direction of vertical formation 107 from wellbore 101, correction in the drilling direction can be made to hit, or avoid, conductive formation 107.

Statistical analysis of measured magnetic fields according to this embodiment of the invention may be carried out in similar manner as described hereinabove relative to Figure 6. History of the measurements made during the drilling operation can be used to generate an expected value at each depth, deviations from which are indicative of an approaching change in formation characteristics, for example due to a new stratum approaching ahead of the drill bit 15. The use of this

history may particularly enable the detection of low conductivity formations ahead of bit 15, by detecting a reduction in dipole moment from that which is otherwise expected. The results of this monitoring can be used to generate a new stratigraphic survey, or to verify and adjust a prior survey.

It is further contemplated that bending strain and flex in drill string 10 and any bottomhole assembly used therewith may be a source of noise, as such strain and flex will tend to disturb the orientation of the dipoles in the material of drill string 10. In situations where such noise is, or is expected to be, significant, it is contemplated that inclinometers, bending strain gages, and the like may be included within tool 23e for detecting such bending. Noise cancellation techniques can then be applied to remove noise which is suspected to be due to such bending.

As a result of this embodiment of the invention, it is contemplated that the presence of a different formation may be detected ahead of drill bit 15. It is particularly contemplated that low conductivity formations, such as hydrocarbon reservoirs, may be so detected. It is further contemplated that this system and method may be used in order to detect the presence of an overpressurized zone ahead of the bit by some distance, such that corrective action may be taken prior to the drill bit 15 reaching the overpressurized zone. For example, lightweight drilling mud may be used for much of the drilling operation, thus providing for fast and efficient drilling. This will allow changing of the drilling mud to a heavier weight upon detecting a conductive layer ahead of the drill bit.

In addition, it is contemplated that this method will also provide for a real-time log of the formations through

which drilling has occurred, with the data acquired during the drilling of the well. This information can be compared against prior information, such as that acquired from neighboring wells, seismic surveys, and the like, to provide a more accurate survey, and to adjust prior surveys to match the attributes measured during drilling.

III. Data Handling

The following portion of this application will describe alternative methods for handling the data generated by the above-described data acquisition methods. As indicated hereinabove, the downhole generation and detection of data allows for higher frequency data to be acquired, providing higher resolution information concerning the surrounding sub-surface geology. Each of these attributes results in more data per unit time than prior methods, particularly when performed real-time during drilling. Accordingly, communication of the data taken, either in raw form or after downhole data processing, to the surface for storage, analysis, and corrective action initiation, is a significant portion of the present invention.

A. High Speed Stress Wave Telemetry

A first approach to this problem is the use of high speed stress wave telemetry. Various techniques for communicating information from downhole to the surface are known, and are believed useful in combination with the present invention. Particular classes of techniques which are contemplated to have sufficient data rate capability for such communication include stress wave telemetry using vibrations which are generated and sensed by piezoelectric

transducers, and also stress wave telemetry where the vibrations are generated by magnetostrictive transmitters.

PCT publications WO 92/01955 and WO 92/02054, published on 6 February 1992, based on international patent applications owned by Atlantic Richfield Company, and both incorporated herein by this reference, describe a high speed stress wave telemetry system useful to communicate the real-time acquired data for the systems described hereinabove to the surface, for analysis. It should be noted that the provision of a downhole computer to process some or all of the data can alternatively be used; in such a case, the results of the downhole computation may then be transmitted to the surface, for analysis thereat, by such a telemetry method.

It is contemplated that the above-identified and incorporated PCT publications will provide full detail concerning the manner in which the real-time acquired data for the systems described hereinabove may be communicated to the surface. As noted therein, various types of encoding of the data may be utilized, including frequency shift keying, phase shift keying, simple repetitive frequency, or amplitude or frequency modulation, could alternatively be used. An example of frequency shift keying of an electrical signal is described in U.S. Patent No. 4,156,229 issued May 22, 1979, and an example of phase shift keying of an electrical signal is described in U.S. Patent No. 4,562,559 issued December 31, 1985, both incorporated herein by reference.

Furthermore, as described in the above-incorporated PCT publications, stress wave telemetry may be accomplished by use of either axial compressional vibrations or by torsional vibrations. Furthermore, as it is well known that drill string and similar structures present non-

uniform frequency response to vibrations, and in particular have various frequencies at which the vibrations are greatly attenuated (i.e., stopbands). As described in the above-incorporated PCT publications, transmission frequencies away from these stop bands should be selected. It is contemplated that the transducers and systems described in the above-incorporated PCT publications will provide stress wave telemetry of data from downhole to the surface at relatively high data rates. As a result, it is contemplated that the data generated and detected downhole according to the data acquisition methods can be communicated in real-time fashion to the surface for analysis thereat, by way of such telemetry.

B. Downhole Computation of Acquired Data

As is evident from the foregoing description, a significantly larger amount of data is acquired in the look-ahead prospecting technologies as compared with previous MWD parameter monitoring, and with surface seismic prospecting techniques. The amount of data acquired is significantly greater than that of conventional MWD, due to the higher sampling frequency required for this high resolution prospecting, and due to the higher number of channels from which the data is acquired. In addition, due to the relatively poor signal/noise ratio expected from this technology, additional data will likely be required and additional processing complexity will be needed to implement noise reduction techniques. Relative to surface seismic prospecting, the frequencies of the energy detected downhole are orders of magnitude greater than that detected by conventional surface seismic detectors, and thus is arriving at a higher data rate.

High data rate telemetry, as discussed hereinabove, allows for a useable portion of such high speed data to be communicated to the surface, enabling the use of downhole generated and downhole detected energy to deduce the structure and properties of strata at and ahead of the drill bit, during drilling. However, even the high data rate telemetry described hereinabove cannot communicate raw data at a rate close to the same order of magnitude of the rate at which modern high speed computing circuits and systems are able to process the same data. Accordingly, it is contemplated that deployment of high speed computing capability to locations downhole will allow for even further exploitation of the energy which is both generated and detected downhole, as described hereinabove. This will also reduce the telemetry requirements, as communication of the results may be done at much slower rates than the communication of the raw data.

However, due to the space available in a downhole tool, as well as the hostile temperature, pressure and other environmental factors downhole, it has been difficult, if not impossible, to physically place sufficient computing capability downhole which is of such power and capacity to adequately deal with the quantities of data contemplated relative to the above data acquisition methods. In recent years, however, significant advances have been made in the integrated circuit art, such that huge data processing capability can now fit into relatively small form factors. Examples of high performance data processing systems of a size suitable for use in a downhole environment, are the T425-25 and T800 transputers available from Inmos Corporation. Each of these transputers, including their own CPU and memory, are useful in performing the processes noted hereinbelow.

According to this embodiment of the invention, multiple transputers are utilized in a downhole environment in data handling unit 40 as shown in Figure 1 hereinabove. In addition, it has been found that certain data structures together with a certain processing methodology are particularly beneficial to the implementation of parallel processing. It is contemplated that these data structures and this methodology, when used with high-speed processing equipment such as the transputers noted hereinabove, will enable downhole data analysis to such an extent that the analysis which is to be performed relative to the above-described look-ahead seismic and electromagnetic surveying techniques may be performed downhole, with only the results communicated to the surface.

Referring now to Figure 13, an example of data handling unit 40' according to this embodiment of the invention will now be described in detail. This example of data handling unit 40' includes three transputers 204, 206, 208 for handling the three fundamental functions of data acquisition, data processing, and output. This embodiment of the invention utilizes a data structure which is particularly well suited for parallel processing, so that more than the three transputers illustrated may be utilized. In particular, Figure 13 illustrates that store transputer 204 receives, formats and stores the incoming data in suitable condition for analysis. Process transputer 206 performs the data analysis algorithms on the data received and stored by store transputer, with host computer 205 controlling its operation. Output transputer 208 receives the results of the processing by process transputer 206, formats the same and presents it to telemetry interface 210, which controls the communication of the results of the processing by way of hardwired electrical telemetry, stress wave telemetry (piezoelectrically or magnetostrictively generated), or

such other technique selected for communicating the results of the data processing to the surface for receipt and further analysis.

By way of example, it is contemplated that store transputer 204 may be of lower capacity and performance than process transputer 206. For example, store transputer 204 may be a T425-25 transputer, while process transputer 206 is a higher capacity and performance T800 transputer. Selection of the particular capacity and performance levels can, of course, be made by one of ordinary skill in the art having knowledge of the volume of data to be processed.

Host computer 205 is a conventional microcomputer, having the primary function of controlling the operation of process transputer 206. In addition, particularly in the case where source energy is to be actively generated downhole (as in the electromagnetic situations described hereinabove), host computer 205 is coupled to transducer array 200 to control the generation of such input energy to the earth surrounding the associated tool 23. Examples of microcomputers which may be used as host computer 205 are general purpose microprocessors (such as the i80386 manufactured and sold by Intel Corporation), or special purpose microcomputers (such as the TMS 320C25 manufactured and sold by Texas Instruments Incorporated).

The architecture of Figure 13 is also useful in conventional above-ground computer systems. Figure 14 illustrates, in block form, a conventional workstation computer architecture using transputers in a similar arrangement as that illustrated in Figure 13. In this example, data source 200' is a digital data source, such as disk storage, analog-to-digital converter output, modem communication ports, etc., which communicate data to interface 202' and in turn to store transputer 204'.

Process transputer 206', in this case, is controlled by host computer 205', with conventional peripherals such as disk storage 205a', CRT monitor 205b', and keyboard 205c' cooperating with host computer to define the task to be performed. Output transputer 208', in this example, generates graphics output of the results of the processing of process transputer 206', and presents these results to CRT output 210'. It is contemplated that the benefits of the data structure and methodology described hereinbelow relative to downhole data handling unit 40' will also be applicable to a conventional computer system such as illustrated in Figure 14.

Referring back to Figure 13 for data handling unit 40', transducer array 200 includes the detectors described herein for the various embodiments of energy detected (seismic, galvanic, induction, etc.), which receive the physical energy from the formation and generate electrical signals responsive thereto. The output of transducer array 200 is received by interface 202 in data handling unit 40', interface 202 including such analog-to-digital conversion circuitry, multiplexing, and other formatting electronics as is conventional in the art for receiving analog electrical signals and communicating the same to data processing systems. The output of interface 202 is connected to store transputer 204 which receives the digital electrical signals from interface 202, and stores the same in memory in conjunction with particular contextual information relating thereto, as will be described in further detail hereinbelow.

As noted hereinabove, store transputer 204 is coupled to process transputer 206 by way of bidirectional link 212, so that th data received and st red by store transputer 204 may be communicated thereto. Bidirectional link 212 is a high speed serial link, capable of communicating digital

data at rates of up to 20 Mbits/second. Process transputer 206 is also connected to host computer 205 by way of bidirectional link 213; in contrast to line 212, link 213 is a relatively slow link due to the limitations of host computer 205. Host computer 205 may be a conventional personal computer, or general or special purpose microprocessor in the same, which selects and controls the processes to be performed by process transputer 206. In this example, host computer 205 also controls transducer array 200, by way of control bus CTRL, so that the receipt of physical inputs thereby and the communication of the same to store transputer 204 is appropriately controlled.

Also as noted hereinabove, process transputer 206 is coupled to output transputer 208 by way of bidirectional link 214, which is a high speed serial link similar to link 212. Output transputer 208 processes the information received from process transputer 206 to place it in the proper format for communication from data handling unit 40', for example by way of telemetry interface 210.

Each of transputers 204, 206, 208, according to the Inmos configuration noted hereinabove, has four link ports available thereto for potential connection to a high speed serial link. In the arrangement of Figure 13, process transputer 206 has the most ports occupied, namely three; transputers 204, 208 each have two ports occupied. Accordingly, transputers 204, 206, 208 may be incorporated into a parallel processing configuration; for example, another process transputer 206 may be connected to the spare port of process transputer 206, with connections to spare ports of store transputer 204 and output transputer 208. Such an arrangement can allow for parallel processing of the particular data analysis routines to be performed on the signals corresp nding to the downhole detected energy.

This described system is therefore capable of handling large amounts of data by way of advanced transputer circuitry, such advanced circuitry allowing for the provision of the computing capability in a downhole environment. In addition, the system described herein provides particular benefits in allowing parallel processing to be advantageously utilized, such parallel processing being particularly useful in performing the data analysis routines contemplated to be necessary for the prospecting systems described herein.

Conclusion

As described hereinabove, the systems according to the present invention allow for looking ahead of and around the drill bit location in a drilling operation, with high resolution local surveying available. Various energy types may be used, each with high resolution due to their high frequency generation; either the raw data may be sent to the surface by high data rate telemetry, or downhole parallel computing power may be used to handle the vast amounts of data generated at the higher frequencies. The advantages of high resolution surveying during drilling include greater likelihood of successful production, optimization of drilling parameters, mud usage, and casing design, and thus safer and more efficient hydrocarbon exploration and production.

While the invention has been described herein relative to its preferred embodiments, it is of course contemplated that modifications of, and alternatives to, these embodiments, such modifications and alternatives obtaining the advantages and benefits of this invention, will be apparent to those of ordinary skill in the art having reference to this specification and its drawings. It is contemplated that such modifications and alternatives are within the scope of this invention as subsequently claimed herein.

WE CLAIM:

1. A method of obtaining information during drilling into the earth, comprising:

drilling into the earth from a surface location, using a drill bit attached to a drill string, to form a wellbore;

imparting energy into the earth surrounding said wellbore, from a source location in said wellbore, during said drilling step;

sensing the imparted energy at a plurality of sensing locations along said wellbore, said sensed energy having traveled through a portion of the earth beneath said drill bit; and

communicating signals corresponding to the sensed energy to the surface location.

2. The method of claim 1, wherein said energy is acoustic vibrational energy.

3. The method of claim 2, wherein the distance between first and second ones of said plurality of sensing locations is greater than one-fourth the wavelength of a signal component of the sensed energy.

4. The method of claim 2, further comprising:

comparing the energy sensed at first and second ones of said plurality of sensing locations to reduce noise in the sensed energy.

5. The method of claim 2, wherein said imparting step is performed by said drill bit during said drilling step.

6. The method of claim 1, wherein said energy is electromagnetic energy.

7. The method of claim 6, wherein said generating step comprises:

sourcing low frequency current into the drill string relative to a lower portion near said drill bit, said drill string and said lower portion electrically insulated from one another;

and wherein said sensing step comprises:

measuring a potential between first and second locations of a tool, said tool disposed between said drill string and said lower portion, said first location being above said second location.

8. The method of claim 7, wherein said sensing step further comprises:

measuring a potential between first and third locations of said tool, said third location being closer to said lower portion than said second location.

9. The method of claim 6, wherein said generating step comprises:

generating eddy currents in the earth surrounding said wellbore.

10. The method of claim 9, wherein said generating step comprises:

energizing a first transmitting coil disposed downhole in said wellbore; and

stopping said energizing step in such a manner that eddy currents are generated in the earth surrounding said wellbore;

and wherein said sensing step comprises:

measuring an induced current in a first sensing coil disposed downhole in said wellbore.

11. The meth d of claim 10, wherein said generating step further comprises:

energizing a second coil disposed downhole in said wellbore, said second coil oriented perpendicularly relative to said first transmitting coil; and

stopping said energizing step in such a manner that eddy currents are generated in the earth surrounding said wellbore;

and wherein said sensing step further comprises:

measuring an induced current in said second coil.

12. The method of claim 1, wherein said communicating step comprises:

transmitting signals corresponding to said sensed energy to the surface location.

13. The method of claim 12, wherein said communicating step comprises:

vibrating said drill string according to said sensed energy.

14. The method of claim 1, further comprising:

performing calculations on said sensed energy with a computer located in said wellbore;

and wherein said communicating step comprises transmitting the results of said step of performing calculations to the surface location.

15. A method of obtaining information during drilling into the earth, comprising:

drilling into the earth from a surface location, using a drill bit attached to a drill string, to form a wellbore;

imparting energy int the earth surrounding said wellbore, from a location in said wellbore, during said drilling step;

sensing the generated energy at a location in said wellbore over a period of time, said sensed energy having traveled through a portion of the earth at a sufficient distance from said wellbore to detect discontinuities in sub-surface geology at locations away from said wellbore so that said sensed energy comprises energy altered by a discontinuity away from said wellbore; and

analyzing the sensed energy to determine the distance of said discontinuity from said wellbore.

16. The method of claim 15, wherein the generated and sensed energy are each acoustic vibrational energy;

wherein the sensed energy comprises direct energy from said imparting step and reflected energy from the discontinuity;

and wherein said analyzing step analyzes the time relationship between the direct and reflected energy.

17. The method of claim 16, wherein said analyzing step further analyzes the phase relationship between the direct and reflected energy.

18. The method of claim 16, wherein said sensing step senses shear and pressure components of the sensed energy.

19. The method of claim 18, wherein said sensed energy comprises direct energy from said imparting step transmitted through said drill string, and directed energy transmitted through a volume of the earth surrounding said drill string;

and further comprising:

determining the ratio of the velocities of the sensed shear and pressure components through the volume of the earth surrounding said drill string.

20. The method of claim 16, wherein said imparting step is performed by said drill bit during said drilling step.

21. The method of claim 15, wherein said energy is electromagnetic energy.

22. The method of claim 21, wherein said generating step comprises:

sourcing low frequency current into the drill string relative to a lower portion near said drill bit, said drill string and said lower portion electrically insulated from one another;

and wherein said sensing step comprises:

measuring a potential between first and second locations of a tool, said tool disposed between said drill string and said lower portion, said first location being above said second location.

23. The method of claim 22, wherein said sensing step further comprises:

measuring a potential between first and third locations of said tool, said third location being closer to said lower portion than said second location.

24. The method of claim 21, wherein said generating step comprises:

energizing a first coil disposed downhole in said wellbore; and

stopping said energizing step in such a manner that eddy currents are generated in the earth surrounding said wellbore;

and wherein said sensing step comprises:

measuring an induced current in said first coil.

25. The method of claim 24, wherein said generating step further comprises:

energizing a second coil disposed downhole in said wellbore, said second coil oriented perpendicularly relative to said first transmitting coil; and

stopping said energizing step in such a manner that eddy currents are generated in the earth surrounding said wellbore;

and wherein said sensing step further comprises:

measuring an induced current in said second coil.

26. The method of claim 15, further comprising:

transmitting signals corresponding to said sensed energy to the surface location;

wherein said analyzing step is performed at the surface.

27. The method of claim 26, wherein said transmitting step comprises:

vibrating said drill string according to said sensed energy.

28. The method of claim 15, wherein said analyzing step comprises:

performing calculations on said sensed energy with a computer located in said wellbore;

and further comprising:

transmitting the results of said step of performing calculations to the surface location.

29. A system for obtaining seismic prospecting information during the drilling of a hydrocarbon well, comprising:

a drill string;

means, located near the distal end of the drill string, for imparting energy into the earth;

a plurality of detectors, a first one of said plurality of detectors located near the distal end of the drill string and a second one of said plurality of detectors located along said drill string spaced-apart from said first one of said plurality of detectors, each of said detectors capable of detecting energy generated by said imparting means after said energy has traveled through a portion of the earth at a sufficient distance from said imparting means to detect discontinuities in sub-surface geology at locations away from said drill string and of generating a signal corresponding to said detected energy; and

means for analyzing signals generated by said plurality of detectors to generate a survey.

30. The system of claim 29, wherein said analyzing means comprises:

a transducer located near and coupled to said first one of said plurality of detectors, for generating a telemetry signal along said drill string corresponding to the signal generated by said first one of said plurality of detectors; and

a computer located at the surface, said computer for receiving the telemetry signal from said transducer and analyzing the corresponding energy detected by said detector.

31. The system of claim 29, wherein said analyzing means comprises:

a computer located near and coupled to each of said plurality of detectors, for analyzing the energy detected by said plurality of detectors; and

means for communicating the results of the analysis by said computer to the surface.

32. The system of claim 29, wherein said imparting means comprises:

a vibrational source.

33. The system of claim 32, wherein the distance between said first and second ones of said plurality of detectors exceeds one-fourth the wavelength of a signal component of the detected energy.

34. The system of claim 32, wherein said vibrational source comprises a drill bit.

35. The system of claim 29, wherein said imparting means comprises:

means for generating a current through the earth between an upper portion of said drill string and a distal portion of said drill string;

and wherein said detector comprises:

a plurality of electrodes spaced apart along said a lower portion of said drill string insulated from said upper portion and said distal portion, said plurality of electrodes comprising a first reference electrode and a second measurement electrode;

means for measuring the voltage between said first reference electrode and said second measurement electrode.

36. The system of claim 35, wherein the distance between said second measurement electrode and said distal portion of the drill string is sufficiently great that a conductive layer ahead of said drill bit affects the voltage measured between said second measurement electrode and said first reference electrode.

37. The system of claim 29, wherein said imparting means comprises a coil.

38. The system of claim 37, wherein said detector comprises said coil and a switching apparatus, said switching apparatus operable so that said coil generates a magnetic field and also, after operation of said switching apparatus, may have a current induced therein responsive to a magnetic field.

39. The system of claim 38, wherein said coil generates a magnetic field with dipole moments parallel to said drill string;

and further comprising a magnetometer for monitoring the orientation of said drill string.

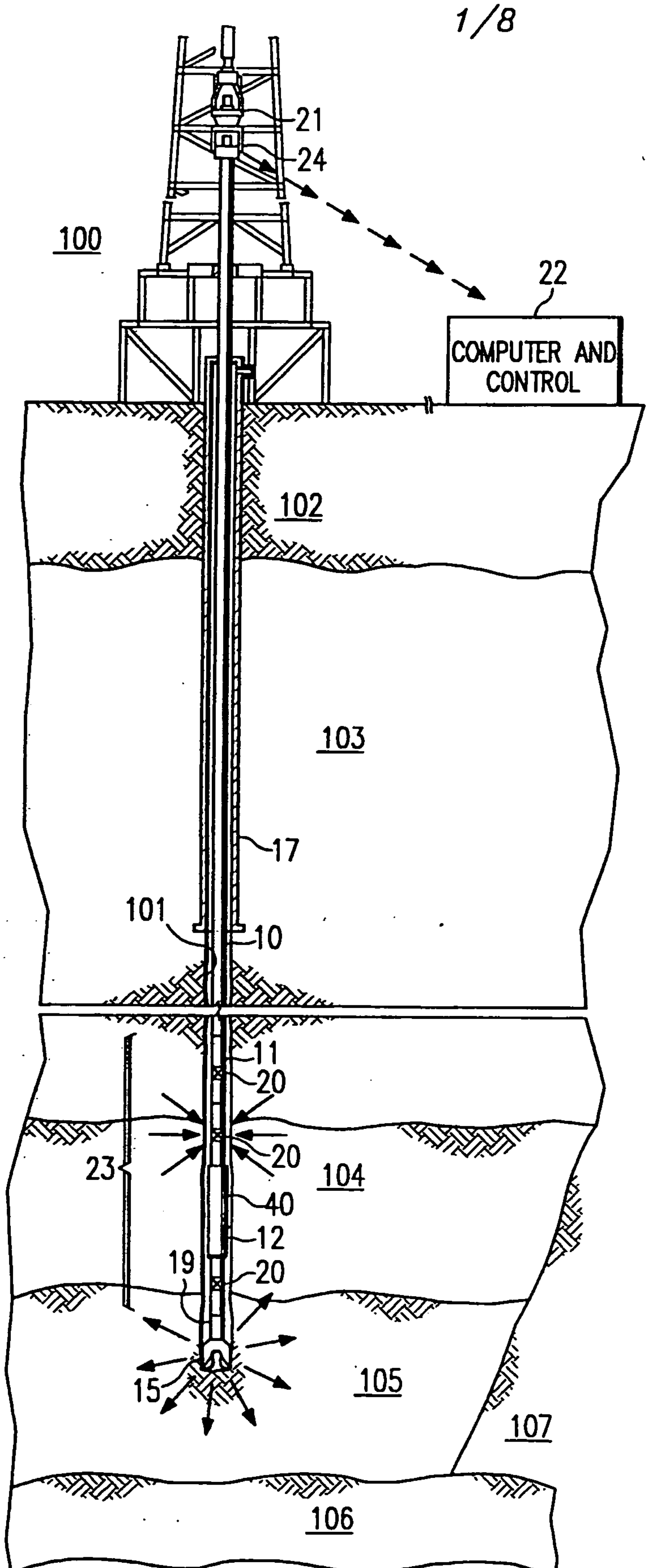

21
24
100
22
COMPUTER AND CONTROL
102
103
17
101
10
11
20
20
23
104
40
12
19
20
15
105
107
106

FIG. 1

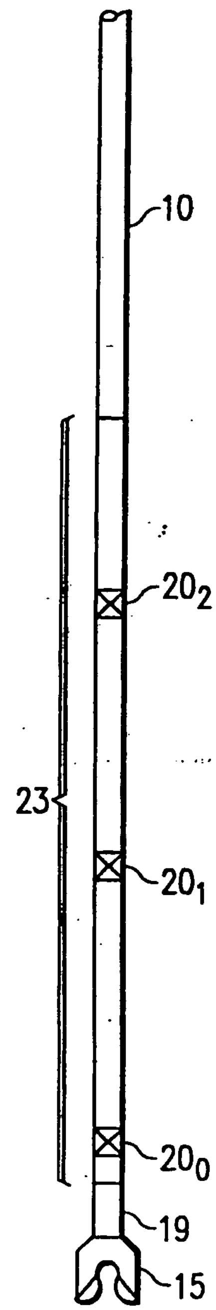

10
20_2
23
20_1
20_0
19
15

FIG. 2a

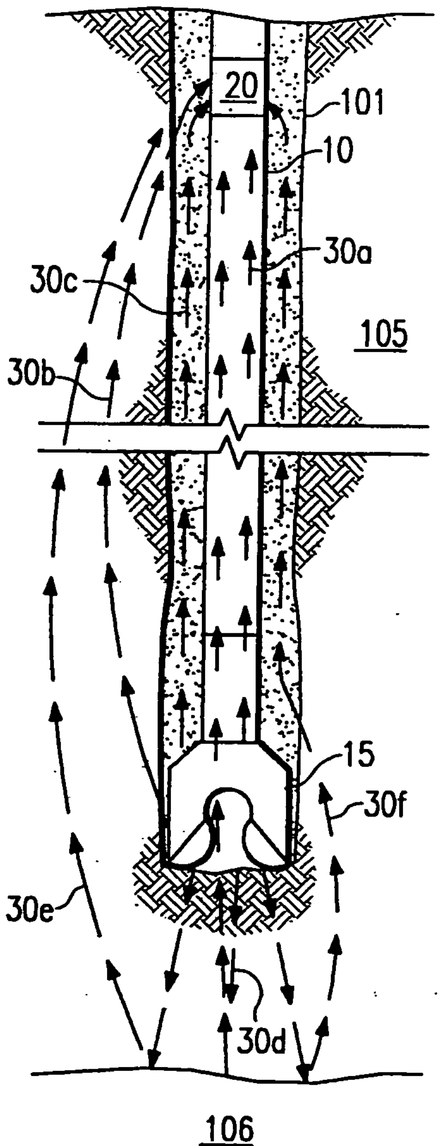


FIG. 2b

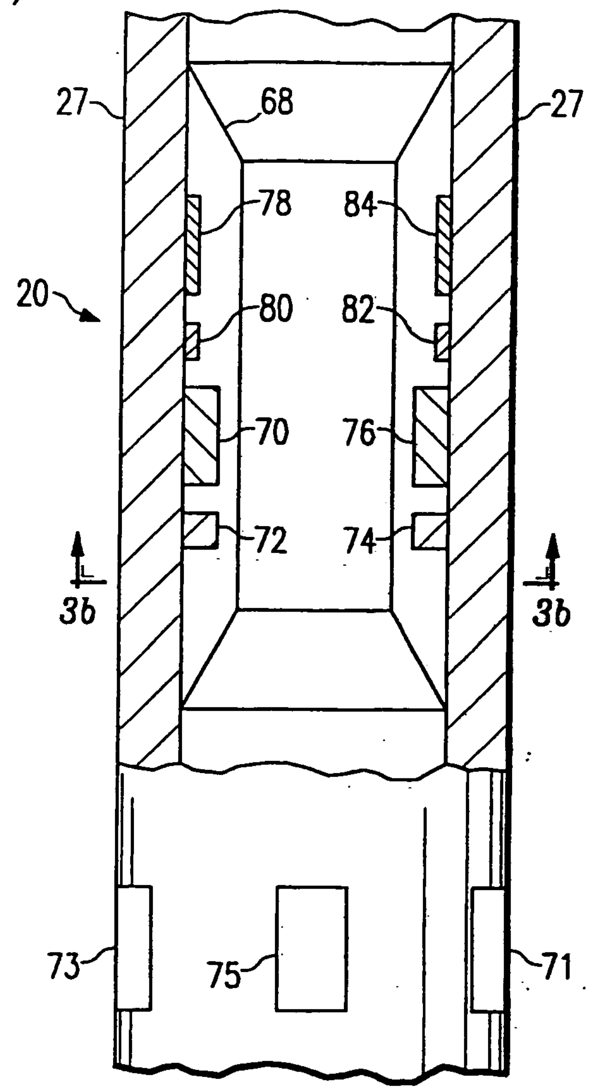


FIG. 3a

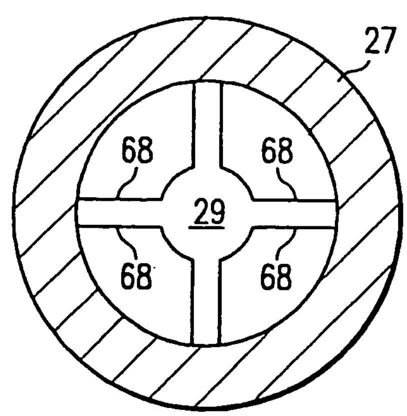


FIG. 3b

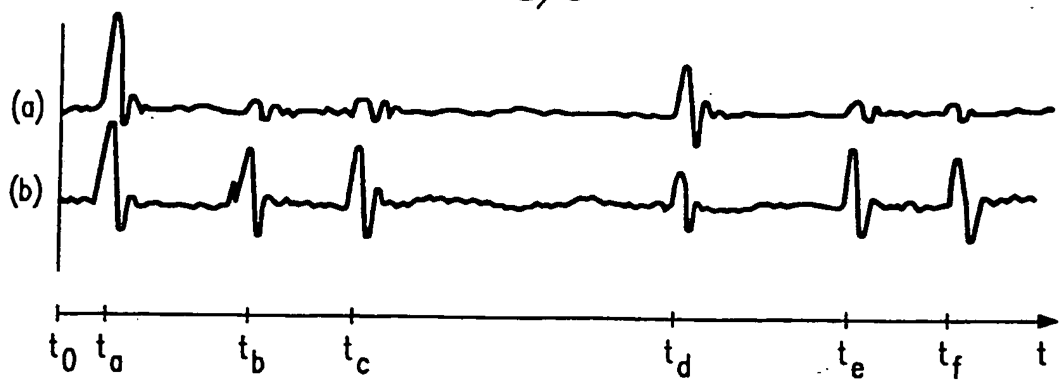


FIG. 4

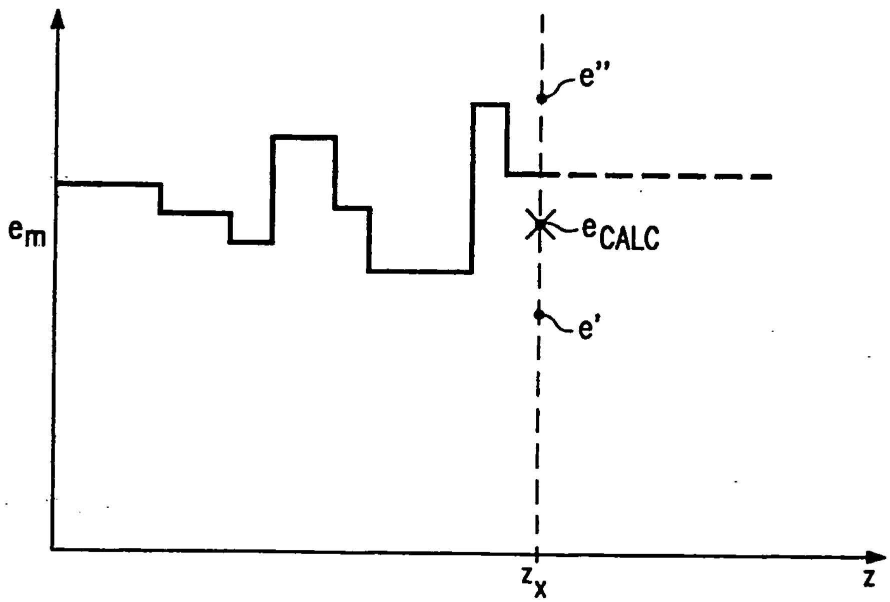


FIG. 6

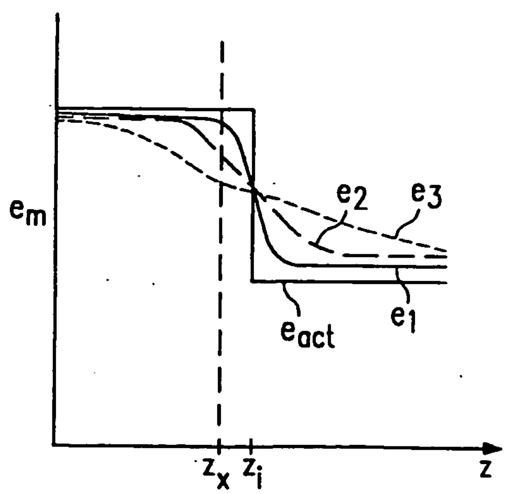


FIG. 7a

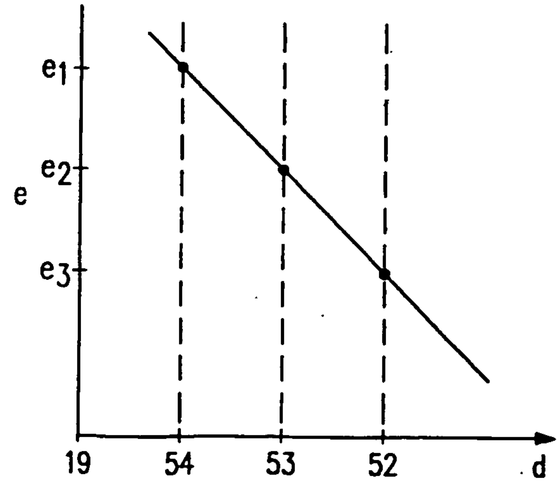


FIG. 7b

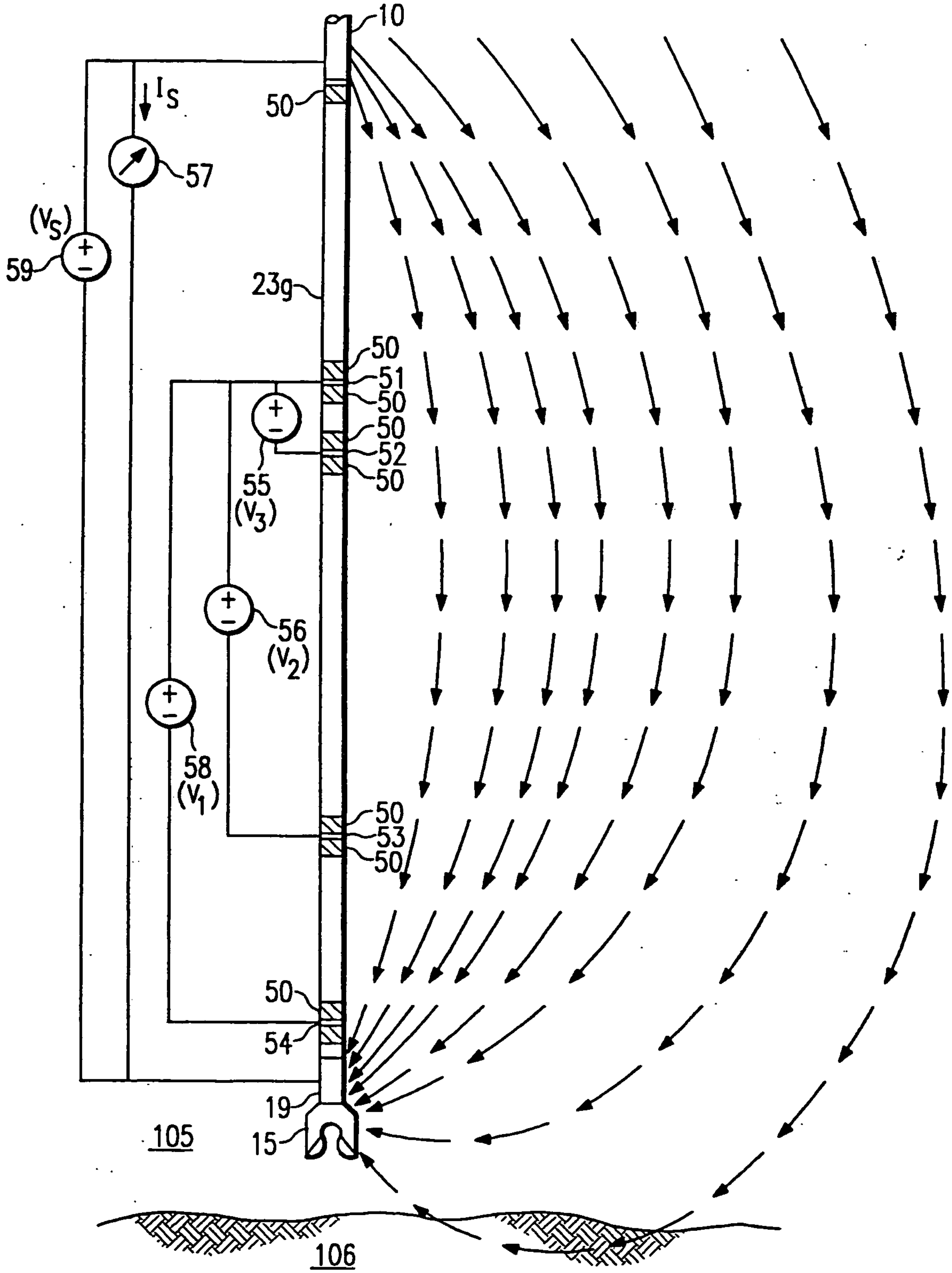

10
I_S
50
57
(V_S)
59
23g
50
51
50
50
52
50
55
(V_3)
56
(V_2)
58
(V_1)
50
53
50
50
54
19
105
15
106

FIG. 5

FIG. 8

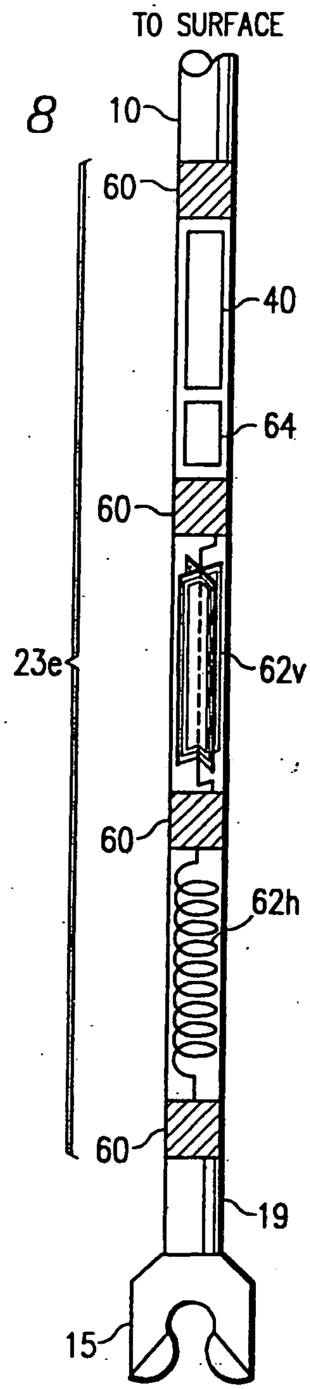


FIG. 9

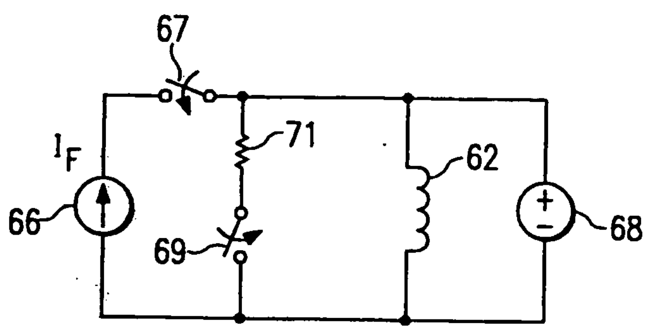
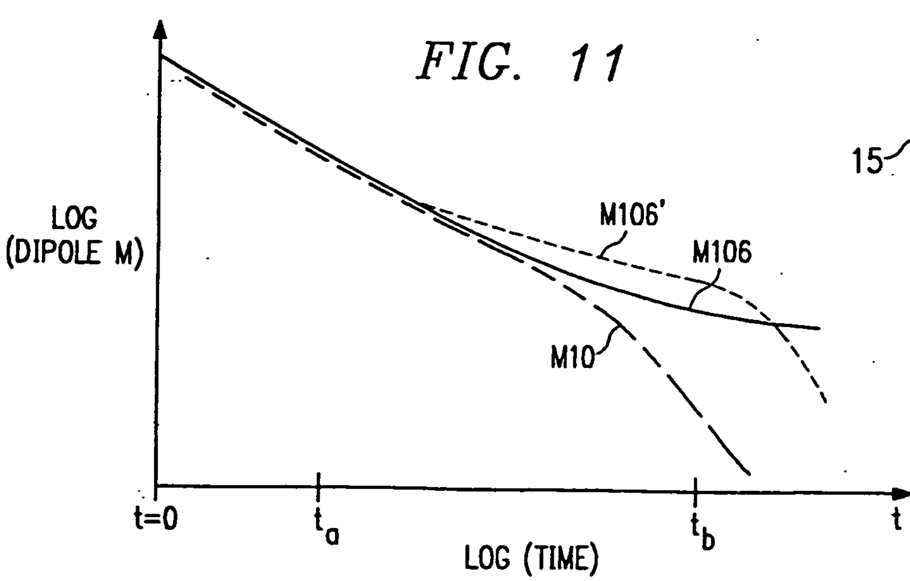


FIG. 11



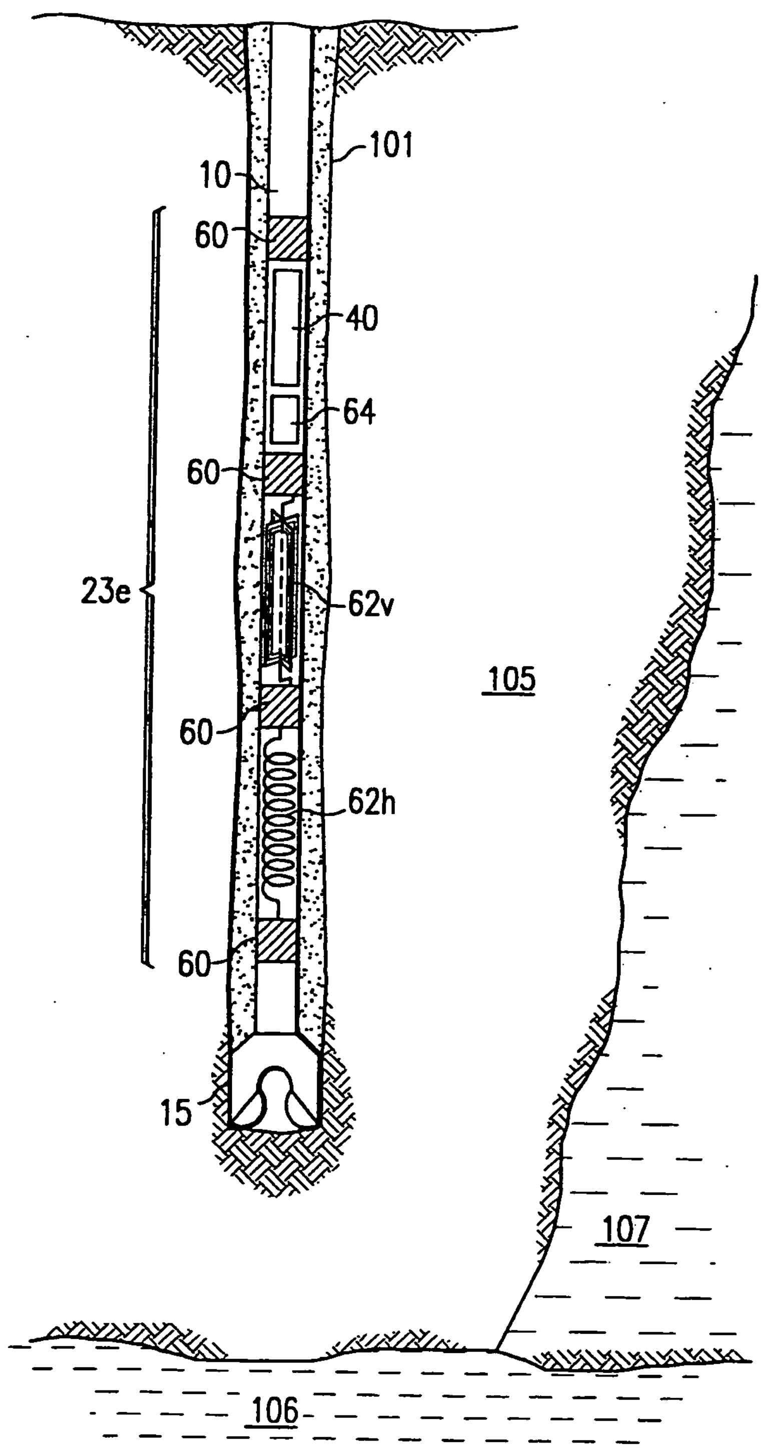


FIG. 10

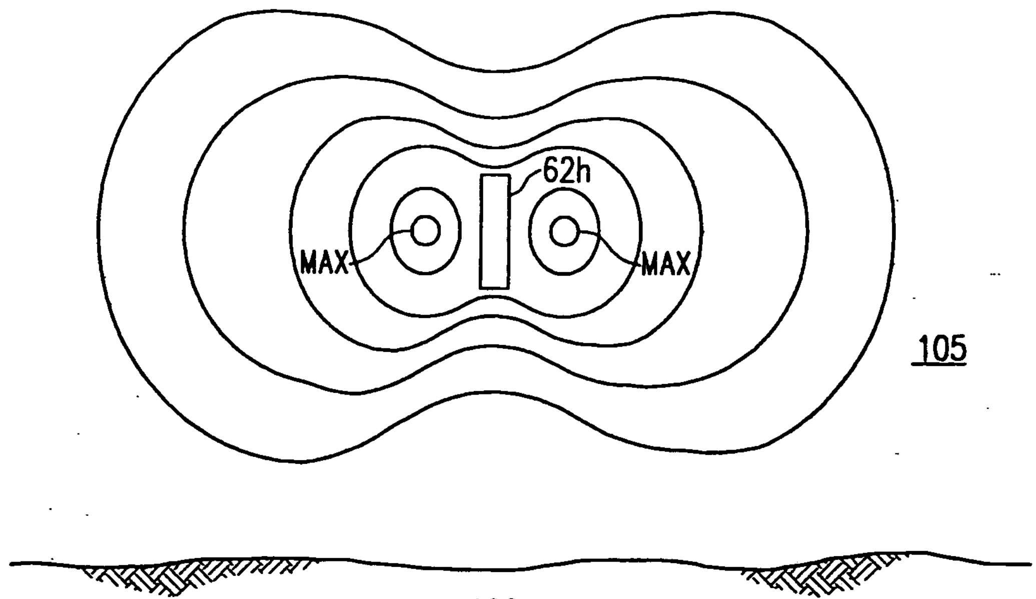


FIG. 12a

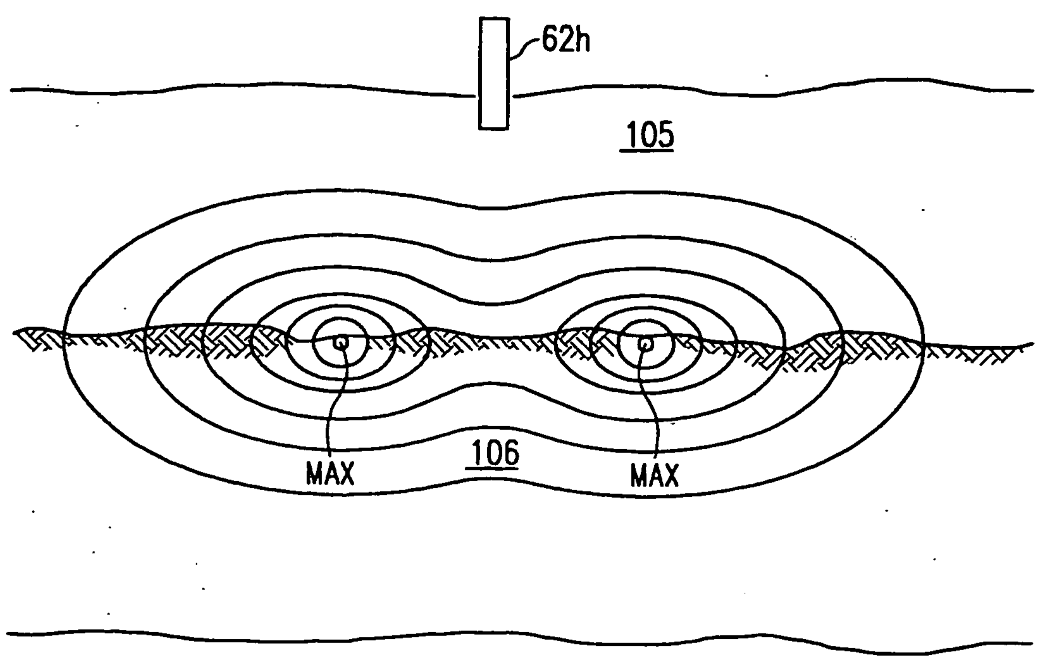


FIG. 12b

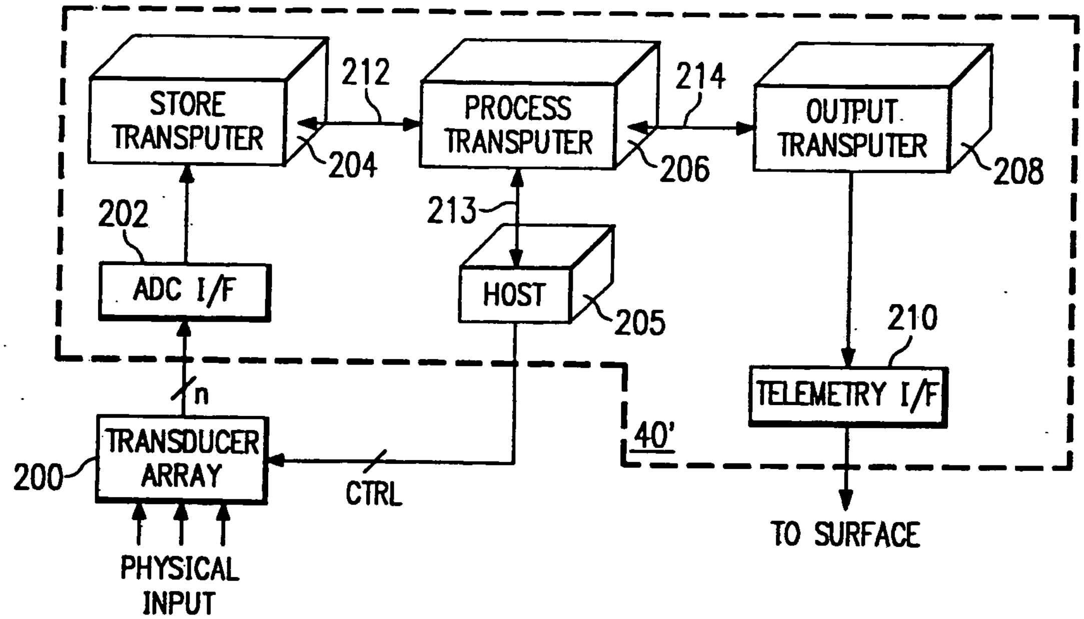

STORE TRANSPUTER
212
PROCESS TRANSPUTER
214
OUTPUT TRANSPUTER
204
206
208
202
213
ADC I/F
HOST
205
210
TELEMETRY I/F
n
40'
TRANSDUCER ARRAY
200
CTRL
TO SURFACE
PHYSICAL INPUT

FIG. 13

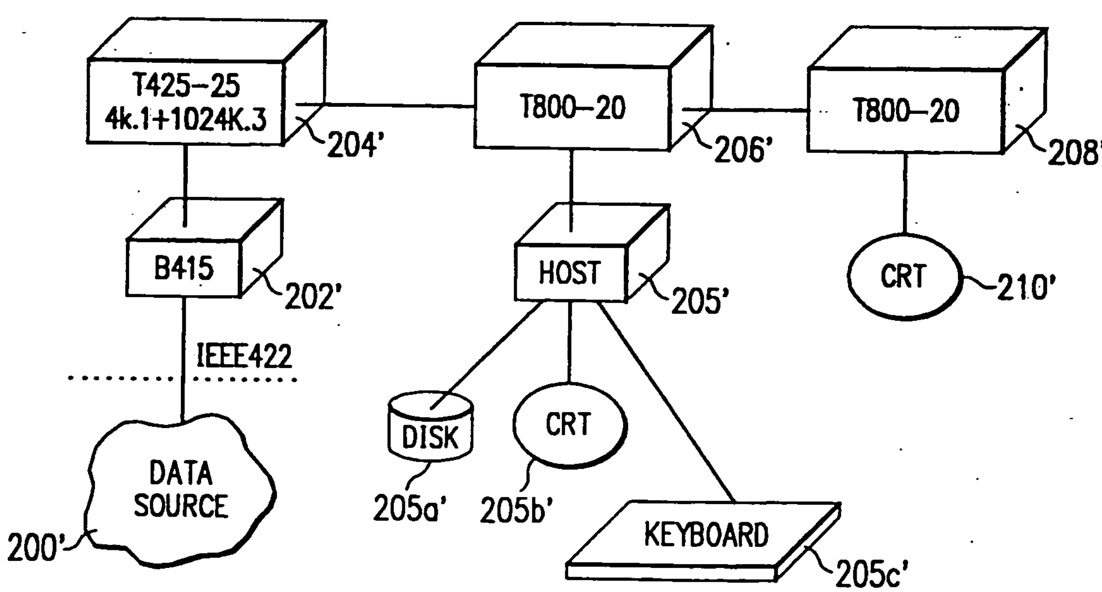

T425–25
4k.1+1024K.3
T800–20
T800–20
204'
206'
208'
B415
202'
HOST
205'
CRT
210'
IEEE422
DISK
CRT
DATA SOURCE
205a'
205b'
KEYBOARD
200'
205c'

FIG. 14

INTERNATIONAL SEARCH REPORT

PCT/US92/08412

A. CLASSIFICATION OF SUBJECT MATTER

IPC(5) :G01V 1/40
US CL :367/25,82 324/338,339,369
According to International Patent Classification (IPC) or to both national classification and IPC

B. FIELDS SEARCHED

Minimum documentation searched (classification system followed by classification symbols)

U.S. : 367/25,82 324/338,339,369 367/86, 181/102, 175/50

Documentation searched other than minimum documentation to the extent that such documents are included in the fields searched

Electronic data base consulted during the international search (name of data base and, where practicable, search terms used)

C. DOCUMENTS CONSIDERED TO BE RELEVANT

Category*	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
X	US,A, 4,474,250 (Dardick) 02 October 1984 See Col. 5, lines 28-51.	1,2
Y	US,A, 5,096,001 (Buytaert et al.) 17 March 1992 See Col. 2, lines 10-36, Col. 3, lines 17-27.	1,2,29-32
Y	US,A, 4,390,975 (Shawhan) 28 June 1983 See entire document.	12,13,26 27
Y	US,A, 4,216,536 (More) 05 August 1980 See entire document.	3-5,33,34
Y	US,A, 2,868,311 (Tullos) 13 January 1959 See entire document.	3-5,33,34

[X] Further documents are listed in the continuation of Box C. [ ] See patent family annex.

* Special categories of cited documents:

"A" document defining the general state of the art which is not considered to be part of particular relevance

"E" earlier document published on or after the international filing date

"L" document which may throw doubts on priority claim(s) or which is cited to establish the publication date of another citation or other special reason (as specified)

"O" document referring to an oral disclosure, use, exhibition or other means

"P" document published prior to the international filing date but later than the priority date claimed

"T" later document published after the international filing date or priority date and not in conflict with the application but cited to understand the principle or theory underlying the invention

"X" document of particular relevance; the claimed invention cannot be considered novel or cannot be considered to involve an inventive step when the document is taken alone

"Y" document of particular relevance; the claimed invention cannot be considered to involve an inventive step when the document is combined with one or more other such documents, such combination being obvious to a person skilled in the art

"&" document member of the same patent family

Date of the actual completion of the international search 16 DECEMBER 1992	Date of mailing of the international search report 27 JAN 1993
Name and mailing address of the ISA/ US Commissioner of Patents and Trademarks Box PCT Washington, D.C. 20231 Facsimile No. NOT APPLICABLE	Authorized officer IAN J. LOBO INTERNATIONAL DIVISION Telephone No. (703) 308-0468

Form PCT/ISA/210 (second sheet)(July 1992)*

INTERNATIONAL SEARCH REPORT

International application No.
PCT/US92/08412

C (Continuation). DOCUMENTS CONSIDERED TO BE RELEVANT

Category*	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
Y	US,A, 4,363,112 (Widrow) 07 December 1982 See entire document.	15-20,28
Y	US,A, 4,706,223 (Zimmerman) 10 November 1987 See entire document.	15-20,28
Y	US,A, 3,748,573 (Vogel) 24 July 1973 See entire document.	6-8,21-23 35,36
Y	US,A, 4,980,643 (Gianzero et al.) 25 December 1990 See Summary	6,9-11,21 24,25,37-39